NEPOOL
NEW ENGLAND POWER POOL
David T. Doot
Secretary

January 30, 2020

VIA ELECTRONIC MAIL

TO: MEMBERS AND ALTERNATES OF THE NEPOOL PARTICIPANTS COMMITTEE

RE: Supplemental Notice of February 6, 2020 NEPOOL Participants Committee Teleconference Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that a meeting of the Participants Committee will be held **via teleconference on *Thursday*, February 6, 2020, 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_2020.php.

For your information, the February 6 meeting will be recorded, as are all the NEPOOL Participants Committee meetings. NEPOOL meetings, while not public, are open to all NEPOOL Participants, their authorized representatives and, except as otherwise limited for discussions in executive session, consumer advocates that are not members, federal and state officials and guests whose attendance has been cleared with the Committee Chair. All those in attendance or participating, either in person or by phone, are required to identify themselves and their affiliation at the meeting. Official records and minutes of meetings are posted publicly. No statements made in NEPOOL meetings are to be quoted or published publicly.

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

FOR PARTICIPANTS WHO DO NOT TYPICALLY RECEIVE INVOICES FROM ISO-NE, PLEASE NOTE THAT THE ISO WILL ISSUE INVOICES FOR 2020 NEPOOL ANNUAL FEES ON FEBRUARY 18, 2020**.** If you are a NEPOOL Participant on January 1, 2020, you will be assessed an Annual Fee, which must be paid on or before the close of business on February 20, 2020, in order to avoid penalties and interest. Please plan accordingly. If there are questions, you can call Pat Gerity (860-275-0533).

Respectfully yours,

/s/
David T. Doot, Secretary

FINAL AGENDA

1. To approve the draft minutes of the Participants Committee meeting held on December 6, 2019.

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

3. To receive an ISO Chief Executive Officer Report.

4. To receive an ISO Chief Operating Officer Report.

5. To consider and take action, as appropriate, on the ISO's proposed Tariff revisions to respond to the FERC's November 22, 2019 order requiring further compliance in New England's *Order 841* electric storage participation proceeding (Docket ER19-470). Background materials and a draft resolution are posted and included 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 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
   - Membership Subcommittee
   - GIS Agreement Working Group
   - Others

8. To receive a report on administrative matters.

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

PRELIMINARY

Pursuant to notice duly given, the annual meeting of the NEPOOL Participants Committee was held beginning at 10:00 a.m. on Friday, December 6, 2019, at the Colonnade Hotel, Boston, Massachusetts. A quorum determined in accordance with the Second Restated NEPOOL Agreement was present and acting throughout the meeting. Attachment 1 identifies the members, alternates, and temporary alternates attending the meeting.

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

APPROVAL OF NOVEMBER 1, 2019 MINUTES

Ms. Chafetz referred the Committee to the preliminary minutes of the November 1, 2019 meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of the November 1, 2019 meeting were unanimously approved as circulated, with an abstention by Mr. Michael Kuser noted.

CONSENT AGENDA

Ms. Chafetz referred the Committee to the Consent Agenda that was circulated and posted in advance of the meeting. Following motion duly made and seconded, the Consent Agenda was unanimously approved without comment, with abstentions by Exelon and Mr. Kuser noted.

REPORT ON ISO CYBER SECURITY EFFORTS

Mr. Brook Colangelo, member of the ISO Board of Directors and Chair of the Board's ~~Temporary~~temporary Special Committee on Information Technology and Cyber Security (ITCSC), gave a presentation on the ISO's current and future efforts ~~on addressing~~to address cyber security challenges. After a brief introduction, Mr. Colangelo noted that technology and software were driving transformation within the industry and the ISO would need to keep pace with the changes. Building upon past efforts of the Board's Audit and Finance Committee on cyber security and technology investment issues, the ISO Board had decided to establish the ITCSC to be chaired by Mr. Colangelo to ~~ensure the ISO is keeping up with the pace of change in~~determine if the Board should establish a standing committee dedicated to technology and best practices in cyber security.

In response to questions, Mr. Colangelo explained that the ITCSC was a special committee tasked with ~~determining how the ISO should employ~~overseeing the ISO's use of technology to ensure cyber security. Based on the ITCSC's findings, it would make recommendations to various other Board committees and ultimately to the Board itself. He stated that the ~~ITSC~~ITCSC planned to engage on these issues with, and identify best practices of, other RTOs/ISOs, as well as the Department of Homeland Security~~. Discussions had already taken place with MISO~~. Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), added that many organizations, including RTOs/ISOs, were sharing cyber security-related information through various means, subject to security limitations.

When asked whether the ITCSC would look at North American Electric Reliability Corporation (NERC) standards to see if they were sufficient to protect the grid from external attack, Mr. Colangelo stated that the ITCSC would take a holistic view of ISO Board oversight and strategic direction regarding cyber security and technology, and would explore various aspects of this topic, but would try its best to avoid prescribing specific outcomes, and leave to management how best to implement protective measures.

A Participant asked whether attempts to infiltrate the system would be often seen in Real-Time or would be uncovered after-the-fact during an audit. Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), responded that the ISO had a 24/7 security operations center that monitors traffic to catch potential penetrations as soon as practicable. Though the ISO had in place processes to look-back and evaluate penetration-related activity, it focused on employing tools that serve as preventative measures and create a robust defense of the ISO's digital perimeter.

Asked whether he could predict the level of resources that would be devoted to cyber security in 5 years' time, Mr. Colangelo described why he could not make such a prediction, citing, in part, examples of threat actors' unceasing efforts to devise new ways to disrupt systems. Concurring, Mr. van Welie described new threat trajectories, including those presented by the increasing deployment of distributed resources, describing examples of how those kinds of resources had been compromised, and the ease and sources of denial-of-service attacks. Mr. Colangelo emphasized that ~~this~~these experiences demonstrated simplicity of execution, as well as the pace of change of technology, ~~dictated~~and compelled that the ISO thoughtfully and thoroughly evaluate its operations.

In response to questions on how the ISO might best take advantage of evolving technological changes, including artificial intelligence (AI), Mr. Colangelo described the ISO's commitment to leveraging change, both from a financial perspective and a research and development perspective. ~~He~~Dr. Chadalavada highlighted work by a group within the ISO that focuses on innovation and uses AI to enhance ISO performance. As appropriate, projects developed by that group would be presented to the ITCSC, the ISO Board and~~, as appropriate,~~ the Participants Committee.

ISO CEO REPORT

Mr. van Welie referred the Committee to the summaries of the ISO Board and Board Committee meetings that had occurred since the November 1 Participants Committee meeting, which had been circulated and posted in advance of the meeting. There were no questions or comments on the summaries.

Mr. van Welie was asked to comment on the recent correspondence exchange with eight of New England's U.S. Senators. He focused his remarks on his responses to the following four points in the Senators' letter: (1) the Senators' suggestion that ISO was not considering the region's environmental and climate goals; (2) the Senators' suggestion that recent ISO market reforms were aimed at maintaining the fossil-fuel mix in contravention of State goals; (3) the Senators' suggestion that the ISO had not maintained an adequate level of engagement and discussion on the evolution of the market; and (4) the Senators' apparent belief that the Energy Security Improvements (ESI) initiative ignores the benefits of renewable resources and would delay market reforms that facilitate public policies.

Mr. van Welie summarized the responses to those assertions as follows:

The ISO respects and understands the States' environmental and climate goals and had implemented over the years a number of market design improvements that advance those goals, with the demonstrated result of material and continuing ~~reduction~~reductions in emissions. The ISO remains committed to, and challenged by, the objective of ensuring that market prices reflect the cost of providing required reliability services.

Recent market reforms~~, particularly~~ of note include the Inventoried Energy Program (IEP) and the Competitive Auctions with Sponsored Policy Resources (CASPR) proposal~~, were, in the case of the~~. IEP~~,~~ was implemented as a temporary measure ~~needed~~ until a longer-term market-based approach could be designed and implemented. CASPR was implemented to provide a second opportunity for renewable resources to clear in the Forward Capacity Market. Neither change would "take the place of, delay, or stand in opposition to long-term, market-based changes to help states meet their public policy goals while maintaining reliability."

The ISO is committed to working with the States and stakeholders to find workable solutions for New England with due consideration for all the goals of the region, the directives of its regulators, and its responsibility to preserve reliability and competitive markets.

In response to concerns about ESI, those market changes are designed to help ensure system reliability, without regard to fuel type. Markets that encourage system reliability will recognize and compensate reliability attributes in a way that will facilitate public policies by accelerating the transition to reliable zero carbon, renewable resources and storage technologies that can provide those reliability attributes. Mr. van Welie noted that the region will need balancing energy, referring to the German concept of Dunkelflaute,[1] ~~or~~during periods of time when days are dark (e.g., a winter day) and high pressure limits wind production. European experience ~~has~~had been that, to maintain reliability, countries must plan a system that can maintain reliability for two weeks when energy from solar and wind resources is restricted or unavailable. For New England that means in the future that the ISO will need balancing energy resources that ~~range~~can produce energy for periods ranging from seconds up to multiple weeks in order reliably to meet a higher electric demand on the system. Thus, Mr. van Welie explained, ESI is meant to address these issues and may accelerate the transition to clean energy.

In responding to questions about his view of the future for traditional resources, Mr. van Welie referenced experiences in Europe and California with de-carbonization. He noted recent reports on the topic from Energy Futures Initiative, the foundation headed by former Energy Secretary Ernest Muniz~~ on the topic~~, and from the Brattle Group. Those reports generally concluded that electricity demand on the grid is going to grow. Further, the reports suggest that regions will need more balancing resources beyond those provided by lithium ion technology, which generally has a short duration discharge. For that reason, as concluded in both reports and

[1] "*dunkelflaute*," when translated to English, means "dark doldrums."

demonstrated through the European experiences, ~~gas~~natural gas-fired and combined-cycle generators ~~will~~would continue to be part of the equation for a long time. To meet de-carbonization goals, changes ~~are~~were needed and ~~are~~were likely to be accomplished through new technology, such as hydrogen-based energy production.

A member stated, based on discussions with some of the Senators that signed the letter, that there was a political perception that the ISO was not doing enough to integrate renewables into the grid. He cautioned the ISO not to miss that view, shared by many constituents, as it responds to the letter. Mr. van Welie acknowledged that perception and the challenges posed by competing policy objectives and overlapping jurisdictions. He concluded by expressing confidence that the region would be able to identify a solution.

Following further discussion, Ms. Chafetz acknowledged the importance of continuing discussion on this topic, indicating that the discussion would pick up again in 2020.

ISO COO REPORT

Dr. Chadalavada reviewed highlights from the December COO report, which was circulated in advance of the meeting and posted on the NEPOOL and ISO websites. He noted that, based on data through November 25, 2019: (i) Energy Market value was $284 million, up $82 million from October 2019 and down $319 million from November 2018; (ii) average natural gas prices over the period were double October 2019 average values; (iii) average Real-Time Hub LMPs ($35.52/MWh) were 74 percent higher than October averages; (iv) average daily (peak hour) Day-Ahead cleared physical Energy, as a percent of forecasted load, was 99.6 percent in November, up from 98.8 percent in October; and (v) daily Net Commitment Period Compensation (NCPC) for November totaled $3.3 million, up $600,000 from October 2019 and down $1.3 million from November 2018. November 2019 NCPC, which was 1.2 percent of total Energy Market value, was comprised of (a) $3.1 million in first contingency payments, up $1.6

million from October, and (b) $103,000 in second contingency payments, down $835,000 from October.

Dr. Chadalavada highlighted two transmission outages, one on Line 349Y from Wakefield Junction in the Northeast Massachusetts and Boston (NEMA) Load Zone, related to work on the Greater Boston Upgrades, which would run through April 2020; the other, a combination of short term outages in the Southeastern Massachusetts and Rhode Island (SEMA/RI) ~~that were~~, expected to last until December 20, 2019. In each case, the outages were likely to require second contingency commitments as load approached or exceeded 18,000 MW. He also noted that recent second contingency commitments required in Maine were not expected to persist past the end of 2019, and that nothing in the plans for 2020 ~~has~~had been identified that would require further second contingency commitments in Maine.

Dr. Chadalavada reported that the ISO Board approved the most current Regional System Plan (RSP19) at the end of October and that, on November 5, 2019, the ISO submitted its informational filing for qualification in the fourteenth Forward Capacity Auction (FCA14) ~~on November 5, 2019~~. He noted also that, for the first time, the ISO would provide its best estimate of the anticipated electrification of the transportation and heating sectors in the 2020 Forecast Report of Capacity, Energy, Loads, and Transmission (2020 CELT Report). Those estimates would come from input provided by State agencies and distribution companies. Similar to previous efforts on energy efficiency estimates, he expected that~~, over time,~~ the accuracy of the projections of the electrification of the transportation and heating sectors would improve over time.

Dr. Chadalavada then turned to an issue experienced in connection with the daylight savings time change on November 3, 2019. He explained that, on non-daylight savings time days, there is a 30-minute window to offer external transaction bids in the Day-Ahead Energy

Market (DAEM) between the close of the New York DAEM at 9:30 a.m. and the close of the New England DAEM at 10:00 a.m. On November 3, a software error in the eMarket application locked out a few Participants from entering or modifying external transactions after 9:00 a.m. The issue was promptly fixed by the early afternoon of November 3. Participants expressed appreciation that Dr. Chadalavada had raised the issue, relayed their experiences, and offered thoughts on process improvements. Dr. Chadalavada reported that the ISO conducted a causal analysis and was in the process of evaluating process improvements. In addition, he indicated that the ISO was exploring the feasibility of extending to 10:30 a.m. the DAEM submission window, and planned to confirm by early 2020 whether or not that extension would be proposed.

Turning to the 2019/2020 Winter Outlook, Dr. Chadalavada reported that the seasonal temperature outlook for the winter months indicated a 33 percent probability that there would be above normal temperatures for the region. Further, precipitation was expected to be at or below normal. He said that the 50/50 winter peak demand forecast was 20,476 MW and the 90/10 winter peak demand forecast was 21,173 MW. He highlighted that the transfer capability on the Northern New York alternating current (AC) ties would be increased from 1,400 MW to 1,500 MW for the winter period to account for lower ambient air conditions. Dr. Chadalavada reminded members of the planned transmission outage that had resulted in a temporary de-rate in the transfer capability on that interface to 500 MW. That outage was scheduled to conclude on December 20, after which that transfer capability would be restored to 1,500 MW.

Dr. Chadalavada then reported on Algonquin Pipeline maintenance efforts. He stated that the reports on inspections were generally positive and inspections were continuing through mid-December. In response to ~~follow up~~follow-up questions, he noted that he was aware of no major issues identified in the inspections to date, that inspections of the trunk lines were mostly if not fully complete, and that some laterals remained to be inspected.

Dr. Chadalavada next reported that, entering the Winter 2019/2020 period, fuel oil tanks were approximately 52 percent full, which was slightly better than where the ISO started in Winter 2018/2019. He also added that he did not believe that fuel oil tanks inventories would be an issue in winter 2019/2020, particularly in light of recent Operating Procedure No. 21 enhancements. He concluded with his opinion that the region was well-positioned for Winter 2019/2020 and was optimistic that the region would fare well absent extraordinary conditions.

2019 NEPOOL ANNUAL REPORT

Ms. Chafetz referred the Committee to the 2019 NEPOOL Annual Report, "Working Together to Shape Tomorrow", distributed at the meeting and posted on the NEPOOL website. Mr. Doot noted that the Annual Report demonstrated that NEPOOL had achieved much in 2019 and could expect continued challenges in 2020. He encouraged Participant feedback on the format and substance of the Annual Report. Ms. Chafetz thanked the Day Pitney team, and Messrs. Harold Blinderman and Pat Gerity particularly, for their efforts to assemble and complete that Annual Report.

ELECTION OF 2020 PARTICIPANTS COMMITTEE OFFICERS

Mr. Chafetz referred the Committee to the proposed slate of 2020 NEPOOL Participants Committee Officers circulated and posted in advance of the meeting, explaining that the vote was to ratify the vote taken by secret ballot the month before and to elect the Secretary and Assistant Secretary for 2020.

The following motion was duly made, seconded and unanimously approved, with an abstention by Mr. Kuser:

> WHEREAS, Section 4.6 of the Participants Committee Bylaws sets forth procedures for the nomination and election of a Chair and Vice-Chairs of the Participants Committee; and

WHEREAS, pursuant to those procedures the individuals identified in the following resolution were nominated and elected for 2020 to the offices of Chair or Vice-Chair, as set forth opposite their names; and

WHEREAS Section 7.1 of the Second Restated NEPOOL Agreement provides that officers be elected at the annual meeting of the Participants Committee.

NOW, THEREFORE, IT IS

RESOLVED, that the Participants Committee hereby adopts and ratifies the results of the election held in accordance with Section 4.6 of the Bylaws and elects the following individuals for 2020 to the offices set forth opposite their names to serve until their successors are elected and qualified:

Chair	Nancy P. Chafetz
Vice-Chair	Calvin A. Bowie
Vice-Chair	David A. Cavanaugh
Vice-Chair	Douglas Hurley
Vice-Chair	Thomas W. Kaslow
Vice-Chair	Michael X. Macrae
Secretary	David T. Doot
Assistant Secretary	Sebastian M. Lombardi

Ms. Chafetz thanked the Participants for their support and the opportunity to lead the Participants Committee for another year.

ESTIMATED BUDGET FOR 2020 NEPOOL EXPENSES

Mr. Kenneth Dell Orto, Budget & Finance Subcommittee (Subcommittee) Chairman, referred the Committee to the materials posted in advance of the meeting concerning the estimated budget for 2020 Participant Expenses (a copy of which is included as Attachment 2 to these minutes). He reported that, consistent with past practice, the Subcommittee worked with NEPOOL Counsel, the ISO and NEPOOL's Independent Financial Advisor to develop the 2020 Budget. He said that the Subcommittee reviewed together and discussed the proposed 2020 Budget and recommended its adoption without objection.

The following motion was duly made, seconded and approved unanimously, with abstentions noted by Littleton (NH), Vermont Electric Cooperative~~,~~ and Mr. Kuser:

> RESOLVED, that the Participants Committee adopts the estimated budget for NEPOOL expenses for 2020 as presented at this meeting.

Acknowledging that this meeting would be ~~his~~Mr. Dell Orto's last as the Chair of the Subcommittee, Ms. Chafetz, on behalf the Participants, thanked ~~Mr. Dell Orto~~him for his tireless efforts, diligence and thoughtful leadership of the Subcommittee. Ms. Chafetz then announced that Ms. Michelle Gardner had agreed to and would serve as the next Chair of the Subcommittee.

MEMBERSHIP SUBCOMMITTEE REPORT: ADVANCED ENERGY ECONOMY (AEE) APPLICATION

Ms. Sarah Bresolin, Membership Subcommittee Chair, referred the Committee to the materials circulated and posted in advance of the meeting regarding an application for NEPOOL membership received by AEE, whose representative was present at the meeting. She said AEE had applied for membership in the Alternative Resources (AR) Sector but it did not meet all existing eligibility criteria for membership in that Sector~~ and the~~. The Subcommittee sought ~~further~~ guidance from the Participants Committee on the Sector or status for which AEE should be considered for membership. Ms. Bresolin reviewed the alternatives that had been considered to that point. The Committee was reminded that no action would be sought until the Membership Subcommittee brought a recommendation or reported back to the Participants Committee, and members offered their perspectives and suggestions on the membership issue.

There was overwhelming support for identifying a basis for AEE membership and participation in the Pool. Some members, however, were concerned with AEE membership in the AR Sector and the precedent that would be established if changes were made to permit their membership in that Sector. A number of members suggested that consideration be given to accepting AEE on the same basis as Fuels Industry Participants.

Following further discussion, Ms. Chafetz urged all those interested to participate in the Membership Subcommittee's December 9 meeting when the AEE matter was scheduled for consideration.

LITIGATION REPORT

Mr. Doot referred the Committee to the December 4 Litigation Report circulated and posted in advance of the meeting. He highlighted the 60-day compliance filing requirement in response to the FERC's order on the region's Order 841 compliance filing, and the possibility that NEPOOL would seek an extension of time to allow the Participants Committee to vote at its February 6 meeting on the changes to be included in the compliance filing before they must be submitted. Ms. Maria Gulluni, ISO General Counsel, added that, while the ISO was still reviewing the Order, the most complicated aspect of the required compliance filing appeared to be related to the DAEM, and on those aspects of the Order, the ISO was contemplating seeking rehearing on or before the December 23, 2019 deadline for such requests.

With respect to return on equity (ROE) issues pending before the FERC, Mr. Doot reported that, on November 21, 2019, the FERC issued Opinion No. 569 in proceedings addressing complaints on ROEs in Midcontinent Independent System Operator (MISO) Control Area. He indicated that, although Opinion No. 569 did not make specific determinations with respect to New England ROE issues, action in the New England ROE cases was likely to be influenced by, if not consistent with, the FERC's methodology for determining a just and reasonable ROE in the MISO proceedings.

In response to questions from the Officers regarding what might be expected from the FERC given the potential addition of a new Commissioner and the expiration of commitments that had resulted in Commissioner recusals in pending proceedings, Mr. Doot referred members to all pending matters reported in the Litigation Report. He noted that some of the higher visibility matters included pending proceedings on transmission ROE, on the PJM Minimum Offer Price Rule (MOPR) ~~proceedings~~, and on numerous New England Capacity Market-related ~~proceedings~~filings that were still before the Commission on rehearing.

Mr. Doot concluded by highlighting the D.C. Circuit's decision to rehear a case *en banc* on the FERC's handling of tolling orders (*Allegheny Defense Project, et al. v. Federal Energy Regulatory Commission*, No. 17-1098 (D.C. Cir.)).

COMMITTEE REPORTS

Markets Committee (MC). Mr. William Fowler, the ~~Markets Committee (~~MC~~)~~ Vice-Chair, reported that the MC was scheduled to meet on December 10–11, 2019 in Westborough. He reported that the MC had tentatively scheduled additional meetings in January, February and March for consideration of the changes to be included in the ESI filing.

Reliability Committee (RC). Mr. Robert Stein, the ~~Reliability Committee (~~RC~~)~~ Vice-Chair, reported that the next meeting would be December 18, 2019. He highlighted a report that the RC would receive from the ISO on ISO efforts to reflect behind-the-meter solar resources in its load forecasts.

Transmission Committee (TC). Mr. José Rotger, the ~~Transmission Committee~~TC Vice-Chair, reported that the next meeting would be held by teleconference on Tuesday December 17 and would include discussion on three FERC-related items: (i) compliance with the FERC's order on New England's Order 841 (storage order) compliance filing; (ii) the ISO's response in the FERC-initiated 206 proceeding on the ISO's Order 1000 exemption; and (iii) Opinion No. 569, the FERC's order on ROE, and what that might mean for the pending New England ROE cases. Looking ahead to January, he noted the possibility that the January ~~Transmission~~

~~Committee~~TC meeting could be re-scheduled or cancelled and for members to stay tuned for further information.

Joint Nominating Committee (JNC). Mr. Doug Hurley reported that , at a meeting in October, the JNC discussed whether to grant a waiver of the age-limit for Mr. Roberto Denis. Following that discussion, the JNC decided to grant that age-limit waiver in order for Mr. Denis to stand for re-election in 2020 for one more three-year term. Accordingly, in 2020, the JNC would be searching for one new director. In each of the following two years, the JNC would be searching for at least two new directors. He reported that the JNC would next meet January 16, 2020, and would review potential candidates to be interviewed in the spring.

Mr. Hurley also reported that ~~at its October meeting~~ the JNC received a request at its October meeting to distribute a document to the Participants Committee listing the directors' expertise and the information used by the JNC to select the next directors. The JNC will provide that document and others to NEPOOL Counsel to distribute it to the Participants Committee.

OTHER BUSINESS

There being no further business, the meeting adjourned at 12:20 p.m.

Respectfully submitted,

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David Doot, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN
DECEMBER 6, 2019 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Acadia Center	End User	Deborah Donovan		
American Petroleum Institute	Fuels Industry Part.	Zoe Cadore		
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		
American PowerNet Management	Supplier			Mary Smith, Mike Macrae
Ashburnham Municipal Light Plant	Publicly Owned		Brian Thomson	
Associated Industries of Massachusetts	End User			Roger Borghesani
AVANGRID: CMP/UI	Transmission		Alan Trotta	
Belmont Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Block Island Utility District	Publicly Owned	Dave Cavanaugh		
Boylston Municipal Light Department	Publicly Owned		Brian Thomson	
BP Energy Company	Supplier			Nancy Chafetz
Braintree Electric Light Department	Publicly Owned			Dave Cavanaugh
Brookfield Renewable Trading and Marketing	Supplier	Aleksandar Mitreski		
Calpine Energy Services, LP	Supplier	Brett Kruse		Bill Fowler
Central Rivers Power	AR-RG	Kevin Telford	Dan Allegretti	
Chester Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned		Brian Thomson	
CLEAResult Consulting, Inc.	AR-DG	Tamara Oldfield (tel)		
Competitive Energy Services, LLC	Supplier			Glenn Poole (tel)
Concord Municipal Light Plant	Publicly Owned		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned	Brian Forshaw (tel)		
Connecticut Office of Consumer Counsel	End User		Joe Rosenthal	
Conservation Law Foundation (CLF)	End User	Jerry Elmer		
Consolidated Edison Energy, Inc. (ConEd)	Supplier	Jeff Dannels (tel)		
CPV Towantic, LLC	Generation	Dan Pierpont		
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	Mike Purdie	Jim Davis	
DTE Energy Trading, Inc.	Supplier			Nancy Chafetz
Dynegy Marketing and Trade, LLC	Supplier			Bill Fowler
Enel X North America, Inc.	AR-LR		Herb Healy	
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin	Joe Dalton	
Entergy Nuclear Power Marketing LLC	Supplier	Ken Dell Orto		Bill Fowler
Eversource Energy	Transmission	James Daly	Cal Bowie	
Excelerate Energy LP	Fuels Industry Part.			Gary Ritter
Exelon Generation Company	Supplier	Steve Kirk	Bill Fowler	
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc.	Supplier	Nancy Chafetz		
Generation Group Member	Generation	Dennis Duffy	Abby Krich	Ron Coutu; R. Stein
Georgetown Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Great River Hydro	AR-RG			Bill Fowler
Groton Electric Light Department	Publicly Owned		Brian Thomson	
Groveland Electric Light Department	Publicly Owned		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc.	Supplier	Louis Guibault (tel)	Bob Stein	
Harvard Dedicated Energy Limited	End User	Mary Smith	Mike Macrae	Doug Hurley
High Liner Foods (USA) Incorporated	End User		William P. Short III	
Hingham Municipal Lighting Plant	Publicly Owned		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned		Brian Thomson	
Holyoke Gas & Electric Department	Publicly Owned		Brian Thomson	
Hull Municipal Lighting Plant	Publicly Owned		Brian Thomson	
Industrial Energy Consumer Group (IECG)	End User	Kevin Penders		

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN
DECEMBER 6, 2019 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Ipswich Municipal Light Department	Publicly Owned		Brian Thomson	
Jericho Power LLC (Jericho)	AR-RG	Mark Spencer		
KCE CT 1, LLC	Provisional	Rachel Goldwassser		
Littleton (MA) Electric Light and Water Department	Publicly Owned		Dave Cavanaugh	
Littleton (NH) Water & Light Department	Publicly Owned	Craig Kieny		Dave Cavanaugh
Long Island Power Authority (LIPA)	Supplier		Bill Killgoar (tel)	
Maine Public Advocate's Office	End User			Jason Frost
Maine Skiing, Inc.	End User	Kevin Penders		
Mansfield Municipal Electric Department	Publicly Owned		Brian Thomson	
Marblehead Municipal Light Department	Publicly Owned		Brian Thomson	
Mass. Attorney General's Office (MA AG)	End User	Christina Belew	Benjamin Griffiths	Rebecca Tepper
Mass. Bay Transportation Authority	Publicly Owned		Dave Cavanaugh	
Mass. Municipal Wholesale Electric Company	Publicly Owned	Brian Thomson		
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	
Middleton Municipal Electric Department	Publicly Owned		Dave Cavanaugh	
National Grid	Transmission	Tim Brennan	Tim Martin	
Natural Resources Defense Council	End User	Bruce Ho		
Nautilus Power, LLC	Generation		Bill Fowler	
New Hampshire Electric Cooperative	Publicly Owned	Steve Kaminski		B. Forshaw (tel); D. Cavanaugh
NextEra Energy Resources, LLC	Generation	Michelle Gardner		
North Attleborough Electric Department	Publicly Owned		Dave Cavanaugh	
Norwood Municipal Light Department	Publicly Owned		Dave Cavanaugh	
NRG Power Marketing LLC	Generation	Neal Fitch	Pete Fuller	
Pascoag Utility District	Publicly Owned		Dave Cavanaugh	
Paxton Municipal Light Department	Publicly Owned		Brian Thomson	
Peabody Municipal Light Department	Publicly Owned		Brian Thomson	
PowerOptions, Inc.	End User	Cindy Arcate		
Princeton Municipal Light Department	Publicly Owned		Brian Thomson	
PSEG Energy Resources & Trade LLC	Supplier	Joel Gordon		
Reading Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Repsol Energy North America Company	Fuels Industry Part.		Nancy Chafetz	
Rowley Municipal Lighting Plant	Publicly Owned		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned		Brian Thomson	
Shrewsbury Electric & Cable Operations	Publicly Owned		Brian Thomson	
South Hadley Electric Light Department	Publicly Owned		Brian Thomson	
Sterling Municipal Electric Light Department	Publicly Owned		Brian Thomson	
Stowe Electric Department	Publicly Owned		Dave Cavanaugh	
Sunrun Inc.	AR-DG			Nancy Chafetz
Taunton Municipal Lighting Plant	Publicly Owned		Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned		Brian Thomson	
The Energy Consortium	End User	Roger Borghesani	Mary Smith	
Transource	Provisional			Dylan Drugan
Union of Concerned Scientists	End User		Francis Pullaro	
Vermont Electric Coop.	Publicly Owned	Craig Kieny		Dave Cavanaugh
Vermont Electric Power Company	Transmission	Frank Ettori		
Vermont Energy Investment Corp (VEIC)	AR-LR		Doug Hurley	
Vermont Public Power Supply Authority	Publicly Owned			Brian Forshaw (tel)
Verso Energy Services LLC	Generation	Glenn Poole		
Village of Hyde Park (VT) Electric Department	Publicly Owned		Dave Cavanaugh	
Vitol Inc.	Supplier	Joe Wadsworth (tel)		Nancy Chafetz

ATTACHMENT 1

**PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN
DECEMBER 6, 2019 MEETING**

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Wakefield Municipal Gas & Light Department	Publicly Owned		Brian Thomson	
Wallingford DPU Electric Division	Publicly Owned		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned		Dave Cavanaugh	
West Boylston Municipal Lighting Plant	Publicly Owned		Brian Thomson	
Westfield Gas & Electric Department	Publicly Owned		Dave Cavanaugh	

ESTIMATED 2020 NEPOOL BUDGET COMPARED TO
2019 NEPOOL BUDGET AND 2019 PROJECTED ACTUAL EXPENSES

Line Items	**2019 Approved Budget**	**2020 Proposed Budget**	**2019 Current Forecast**
NEPOOL Counsel Fees (1)	$3,950,000	$ 4,100,000	$ 4,290,000
NEPOOL Counsel Disbursements (1)	$ 40,000	$ 40,000	$ 40,000
Independent Financial Advisor Fees and Disbursements (2)	$ 40,000	$ 45,000	$ 45,000
Committee Meeting Expenses (3)	$ 675,000	$ 725,000	$ 705,000
Generation Information System (4)	$ 850,000	$ 945,000	$ 825,000
Credit Insurance Premium (3)	$ 720,000	$ 510,000	$ 720,000
NEPOOL Audit Management Subcommittee ("NAMS") Consultant (5)	$ 0	$ 0	$ 0
SUBTOTAL EXPENSES	$6,275,000	$6,365,000	$6,625,000
Revenue			
NEPOOL Membership Fees (3) (6)	($2,060,000)	($2,070,000)	($2,187,000)
Generation Information System (4) (7)	($ 850,000)	($ 945,000)	($ 825,000)
Credit Insurance Premium (3) (8)	($ 720,000)	($ 510,000)	($ 720,000)
TOTAL REVENUE	($3,630,000)	($3,525,000)	($3,732,000)
TOTAL NEPOOL EXPENSES	**$2,645,000**	**$2,840,000**	**$2,893,000**

Notes

(1) 2020 proposed estimate provided by Day Pitney LLP, NEPOOL counsel.

(2) 2020 proposed estimate provided by Michael M. Mackles, NEPOOL's Independent Financial Advisor.

(3) 2020 proposed estimate provided by ISO New England Inc.

(4) 2020 proposed estimate provided by APX, Inc., GIS Administrator.

(5) If NEPOOL determines that an audit should be performed in 2020, funding for that audit will be addressed separately.

(6) The 2020 proposed estimate is based on the 2019 actual receipts through October 2019, plus a forecast for new members for the remainder of the year. The breakdown for the proposed budget is approximately: 381 members at $5,000 each, 28 members at $1,000 each, 12 members at $500 each, 29

members at $1,500 each, and 33 members of large end users and MPEU's. This estimate takes into account the terminations throughout the year.

(7) GIS costs, other than those associated with accessing the GIS through the application programming interface ("API") are paid by "GIS Participants" under Allocation of Costs Related to Generation Information System, which was approved by the NEPOOL Participants Committee on June 21, 2002. GIS costs associated with accessing the GIS through the API are paid by the GIS account holders using that API.

(8) Credit insurance premium is paid by Qualifying Market Participants according to methodology described in Section IX of the ISO Financial Assurance Policy. The 2020 premium is based on 2019 annual policy sales.

CONSENT AGENDA

Reliability Committee

From the previously-circulated notice of actions of the Reliability Committee's January 22, 2020 meeting, dated January 23, 2020:[1]

1. **OP-10 Revisions (References to LCC instructions and EOP-004 deleted; editorial, formatting revisions)**

   Support revisions to ISO Operating Procedure (OP) No. 10 (Emergency Incident and Disturbance Notifications), which delete references to Local Control Center Instructions, delete a paragraph from the Introduction referencing NERC Reliability Standard EOP-004, and incorporate editorial and formatting revisions, all as recommended by the Reliability Committee at its January 22, 2020 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.

2. **OP-14 Revisions (DE Voice communication requirement updates; DDMS usage clarifications)**

   Support revisions to OP-14 (Technical Requirements for Generators, Demand Response Resources, Asset Related Demands and Alternative Technology Regulation Resources), which update the voice communication requirement for Designated Entities (DE) and clarify the use of the Dynamic Data Management System (DDMS), as recommended by the Reliability Committee at its January 22, 2020 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 notice of actions of the Reliability Committee's December 18, 2019 meeting, dated December 19, 2019:[2]

3. **Revisions to OP-11 and Appendices E & F to OP-11 (Black Start Resource Administration, DBR Test Log and Instructions for Completing DBR Test Log)**

   Support revisions to OP No. 11 (Black Start Administration) (OP-11), Appendix E (Designated Black Start Resource (DBR) Test Log) (OP-11E), and Appendix F (Instructions for Completing DBR Test Log) (OP-11F), that clarify the demonstration of stable operation of a DBR to be consistent with NPCC D8, noting the evaluation criteria for a DBR includes its geographic location, clarify the timing of when the ISO's System Restoration Working Group (SRWG) discusses a potential DBRs feasibility study, and incorporate minor grammatical revisions, all as recommended by the Reliability Committee at its December 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.

4. **OP-22 Revisions (Disturbance Monitoring Requirements)**

   Support revisions to OP No. 22 (Disturbance Monitoring Requirements) (OP-22), which reflect the edits resulting from October Reliability Committee feedback and extensive discussion with the SPWG that center on the timelines and actions for equipment failure, as recommended by the Reliability Committee at its December 18, 2019 meeting, with such further non-material changes as the Chair and Vice-Chair of the Reliability Committee may approve.

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

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

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

5. Revisions to PP-4, PP-5, PP-5-1, PP-5-3, PP-5-6, and PP-10 (Competitive Transmission Solicitation Revisions)

Support revisions to ISO Planning Procedure (PP) Nos. 4 (Procedure for Pool-Supported PTF Cost Review), 5 (Procedure for Reporting Notice of Intent to Construct or Change Facilities in Accordance with Section I.3.9 of the ISO New England Tariff (Proposed Plan Application Procedure)), 5-1 (Procedure for Review of Governance Participant's Proposed Plans (Section I.3.9 Applications: Requirements, Procedures and Forms)), 5-3 (Guidelines for Conducting and Evaluating Proposed Plan Application Analysis), 5-6 (Interconnection Planning Procedure for Generation and Elective Transmission Upgrades), and 10 (Planning Procedure to Support the Forward Capacity Market), which incorporate competitive transmission solicitation enhancements, as recommended by the Reliability Committee at its December 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.

Markets Committee

From the previously-circulated notice of actions of the Markets Committee's January 14-15, 2020 meeting, dated January 15, 2020:[3]

6. Tariff Revisions (NCPC Audit Eligibility Clean Up)

Support revisions to the ISO New England Tariff to clarify eligibility to receive Net Commitment Period (NCPC) credits, as recommended by the Markets Committee at its January 14-15, 2020 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 unanimously approved, with one abstention from the End User Sector noted.

[3] Markets Committee Notices of Actions are posted on the ISO-NE website at: https://www.iso-ne.com/committees/markets/markets-committee/?document-type=Committee%20Actions.

Summary of ISO New England Board and Committee Meetings

February 6, 2020 Participants Committee Meeting

Since the last update, the Compensation and Human Resources Committee, the Markets Committee, the System Planning and Reliability Committee, the Nominating and Governance Committee, and the Special Committee on IT and Cyber Security each met on December 12 in Holyoke. In addition, the Nominating and Governance Committee met by teleconference on January 6. The Audit and Finance Committee, the Compensation and Human Resources Committee, the Markets Committee and the System Planning and Reliability Committee each met on January 15 in Holyoke. The Board of Directors also met with the NERC Board of Trustees on January 15, and held its regular meeting on January 16.

The Audit and Finance Committee met in January to review the corporate goals for 2020 and to assess achievement of 2019 corporate goals during executive session. The Committee was also provided with a report on the annual process to confirm Code of Conduct compliance, and received an update on cyber security.

The Compensation and Human Resources Committee met in December and reviewed the goal setting, assessment and compensation schedule for 2020. The Committee also reviewed its calendar for the upcoming year. In January, the Committee met in executive session to consider corporate performance and the achievement of corporate goals for 2019. The Committee also held a preliminary discussion related to 2020 officer compensation and, with the Company's outside compensation consultant, considered the reasonableness of that compensation when compared to similarly-situated companies.

The Markets Committee met in December and received an update on the Energy Security Initiative ("ESI") project, and particularly discussed stakeholder concerns about the sufficiency of the ESI incentives. The Committee also discussed the application of the Minimum Offer Price Rule to battery storage, and held an executive session to review the corporate goals for 2020. At the Committee's January meeting, it reviewed reports from both the Internal and External Market Monitors on key market issues during the 2019 fall season, and received an update on ESI, with a particular focus on the Energy Imbalance Reserves design. During executive session, the Committee assessed achievement of 2019 corporate goals, and completed its annual review of the scope of coverage and performance of the Internal and External Market Monitoring Units.

The Committee considered the 2020 work plan of the Internal Market Monitor, and reviewed his 2019 performance and proposed compensation.

The System Planning and Reliability Committee met in December and was provided with an overview of activities and events that were a major focus during the late summer and fall of 2019, including qualifications for Forward Capacity Auction #14, the cluster study process to address the queue backlog in Maine, ongoing FERC Order 1000 implementation and winter preparedness. In addition, the Committee previewed activities anticipated to be a major focus for the first quarter of 2020. Next, the Committee discussed potential enhancements to the Regional System Plan, reviewed a dashboard summary of ongoing projects, received an update on the system operations outlook for Winter 2019-2020, and reviewed the status of Regional System Plan projects. The Committee also reviewed its calendar for 2020, and held an executive session to discuss corporate goals for 2020. In January, the Committee held an executive session to assess achievement of 2019 corporate goals. During regular session, the Committee received an update on compliance with NERC and NPCC standards, including a summary of NPCC's 2019 compliance monitoring and enforcement and an overview of NERC and NPCC areas of focus for 2020.

The Nominating and Governance Committee met in December and received a report on Joint Nominating Committee ("JNC") activities, and noted that the JNC had approved an age limit waiver enabling Mr. Denis to stand for re-election to a third term. Next, the Committee discussed the strategic planning process for 2020 and Board oversight thereof, with the objective of including oversight of the process in the Nominating and Governance Committee charter. The Committee met again in January, and agreed to recommend to the Board a revised charter that includes oversight of the strategic planning process. (The revised charter also clarifies the Board nominating process.) The Committee also reviewed a calendar of strategic planning topics for 2020, including meetings with stakeholders, speakers and site visits. With regard to meetings with stakeholders, the Committee noted that there are a number of opportunities scheduled this year to discuss topics of strategic importance, including meetings with NECPUC in March and November, and NEPOOL in June and November.

The Special Committee on IT and Cyber Security convened in December and discussed the scope of its assignment and the focus of its future meetings. The Committee also considered the possibility of inviting an outside speaker to discuss best practices for information technology governance. The Committee agreed that its work would culminate with a recommendation to the Nominating and Governance Committee regarding the Company's information technology governance and the need for a standing committee.

The Board of Directors convened in January. The day prior to its meeting, the Board met with the NERC Board of Trustees to hear a presentation on NERC strategic initiatives and the New England region. The next day, the Board reviewed and approved the proposed 2020 strategic planning process, including activities to facilitate Board oversight of the process and its output. The Board also received reports from the standing committees outlining highlights from their recent meetings. During the Nominating and Governance Committee report, the Board approved changes to the charter to the Board nominating process, and additional language regarding the delegation of authority for the strategic planning process. (The revised charter has been posted to the ISO's website.) Next, the Board received an update on long-term plans to enhance the ISO's modeling/simulation capability to analyze the reliability, operational, and economic impacts of various scenarios for the evolving power grid and wholesale markets in New England. Finally, while in executive session, the Board approved the Company's corporate goals for 2020.

NEPOOL Participants Committee Report

February 2020

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Energy market value over the period was $280M, down $188M from December 2019 and down $391M from January 2019
    - January natural gas prices over the period were 38% lower than December average values
    - Average RT Hub Locational Marginal Prices ($26.29/MWh) over the period were 39% lower than December averages
      - DA Hub: $26.66/MWh
    - Average January 2020 natural gas prices and RT Hub LMPs over the period were down 58% and 49%, respectively, from January 2019 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 99.5% during January, up from 98.7% during December*
    - The minimum value for the month was 94.8% on Friday, January 10th, 2020

DATA THROUGH JANUARY 29, EXCEPT WHERE NOTED.

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

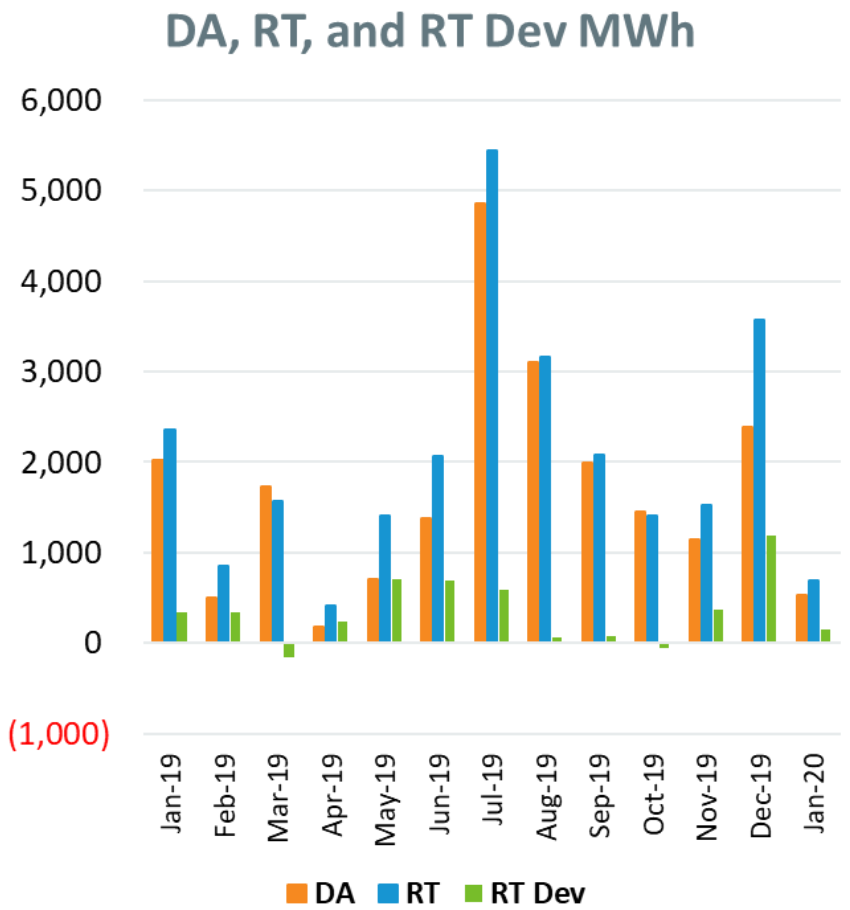
*DA Cleared Physical Energy is the sum of Generation and Net Imports cleared in the DA Energy Market

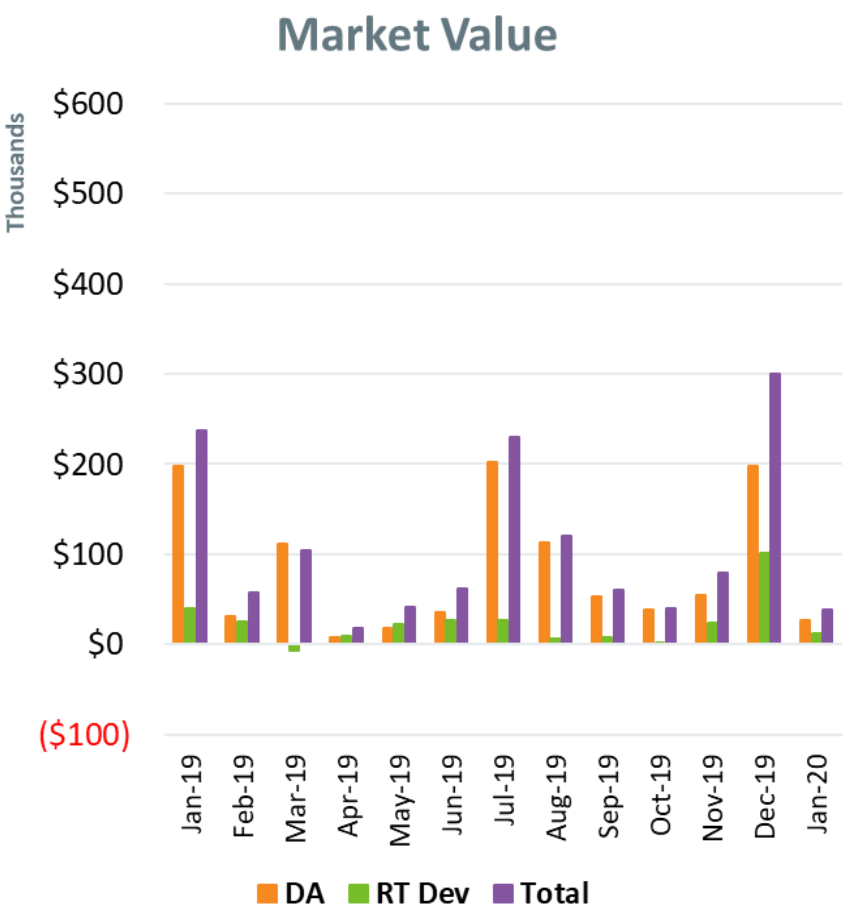
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - January NCPC payments totaled $1.6M over the period, down $3.1M from December and down $0.6M from January 2019
    - First Contingency* payments totaled $1.5M, down $0.5M from December
      - $1.5M paid to internal resources, down $0.4M from December
        - » $404K charged to DALO, $482K to RT Deviations, $621K to RTLO
      - $2K paid to resources at external locations, down $168K from December
        - » Charged to RT Deviations
    - Second Contingency payments totaled $108K, down $2.5M from December
  - NCPC payments over the period as percent of Energy Market value were 0.6%

* NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $172K; Rapid Response Pricing (RRP) Opportunity Cost - $147K; Posturing - $84K; Generator Performance Auditing (GPA) - $219K

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

- FCA 14 was held February 3-4
- On January 23, the ISO sent a short survey to New England stakeholders as a means to provide input to possible enhancements to the Regional System Plan
  - Responses are due February 13
- The Public Policy Process was initiated on January 14
  - Stakeholder input on federal, state, and local Public Policy Requirements must be submitted by February 28
- Boston 2028 RFP Phase One Proposals must be submitted by 11:00 p.m. on March 4

Forward Capacity Market (FCM) Highlights

- CCP 10 (2019-2020)
  - Late, new resources (regardless of size) are being monitored closely
- CCP 11 (2020-2021)
  - Third and final annual reconfiguration auction (ARA3) to be held March 2-4 and results to be posted no later than April 1
    - FERC approved ICR & Related Values for ARA3 on January 6
- CCP 12 (2021-2022)
  - Second reconfiguration auction (ARA2) will be August 3-5 and results to be posted by September 2
    - FERC approved ICR & Related Values for ARA2 on January 6

CCP – Capacity Commitment Period
ICR – Installed Capacity Requirement

Forward Capacity Market (FCM) Highlights

- CCP 13 (2022-2023)
  - First reconfiguration auction (ARA1) will be June 1-3, and results to be posted by July 1
    - FERC approved ICR & Related Values for ARA1 on January 6
- CCP 14 (2023-2024)
  - FCA 14 was held February 3-4

FCA – Forward Capacity Auction

FCM Highlights, cont.

- CCP 15 (2024-2025)
  - The qualification process has started, and training materials are under development
  - Topology certifications were sent to the TOs on October 9, 2019
  - Capacity zone development discussions began in November 2019 at the PAC meeting
    - All subsequent reconfiguration auctions model the same zones as the FCA
  - ICR & Related Values development will commence in May with discussions at the PSPC

Load Forecast

- The 2020 load forecast process has begun
  - Energy-Efficiency Forecast Working Group WebEx will be held on February 13
  - Distributed Generation Forecast Working Group meeting will be held on February 14
  - Load Forecast Committee meeting will be held on February 18
- Efforts continue to enhance load forecast models and tools to improve day-ahead and long-term load forecast performance
- ISO is developing forecasts of the anticipated energy and demand impacts of electrification of the transportation and heating sectors for incorporation in the 2020 CELT forecast
  - Methodologies and supporting assumptions are being discussed as part of the annual Load Forecast Committee stakeholder process

FERC Order 1000

- Qualified Transmission Project Sponsor (QTPS)
  - 23 companies have achieved QTPS status
  - 2 companies are currently moving through the QTPS application process
- The ISO issued the Boston 2028 request for proposal (RFP) on 12/20/2019, which is its first RFP for a competitively-selected transmission solution
  - Phase One Proposals must be submitted by 11:00 p.m. on 3/4/2020
- The ISO filed a response on 12/27/2019 to a 10/17/2019 FERC Section 206 Proceeding regarding the ISO's implementation of Order 1000 time-sensitive needs for immediate need reliability projects (i.e., projects needed to meet reliability needs that are determined to exist three years or less from the completion of a Needs Assessment)
- The Public Policy Process was initiated on 1/14/20
  - Stakeholder input on federal, state, and local Public Policy Requirements must be submitted by 2/28/20

Highlights

- The lowest 50/50 and 90/10 Winter Operable Capacity Margins are projected for week beginning February 1, 2020.

- The lowest 50/50 and 90/10 Preliminary Spring Operable Capacity Margins are projected for week beginning May 9, 2020.

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (9.0°F) Max: 74°F, Min: 14°F Precipitation: 1.39" – Below Normal Normal: 3.36" Snow: 3.1"	Hartford	Temperature: Above Normal (6.9°F) Max: 70°F, Min: 4°F Precipitation: 1.79" – Below Normal Normal: 3.23" Snow: 3.3"

Peak Load:	17,934 MW	January 20,2020	18:00 (ending)

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

Procedure	Declared	Cancelled	
None for January 2020			

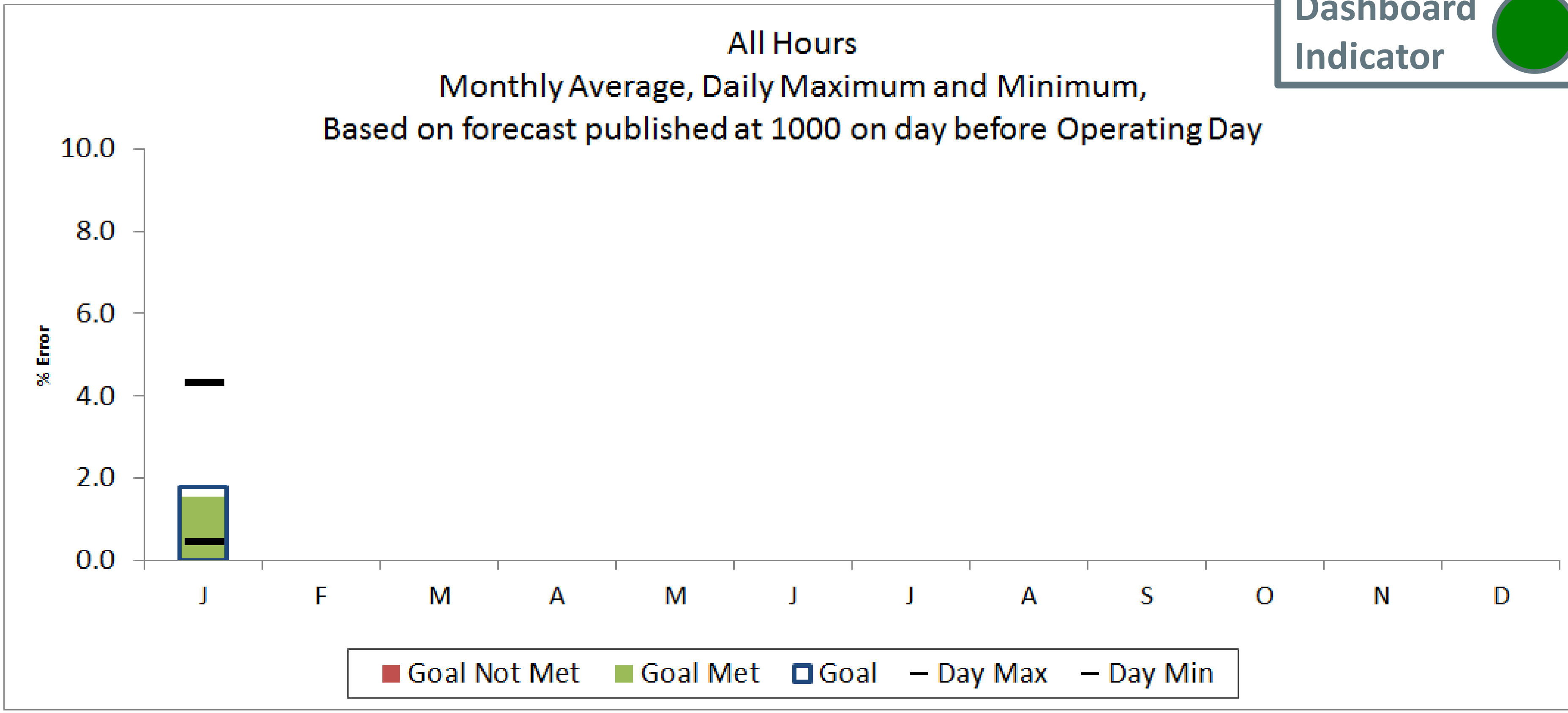
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
1/13	IESO	1400
1/16	NBPSO	350
1/21	IESO	880
1/23	PJM	1082
1/31	IESO	945

2020 System Operations - Load Forecast Accuracy

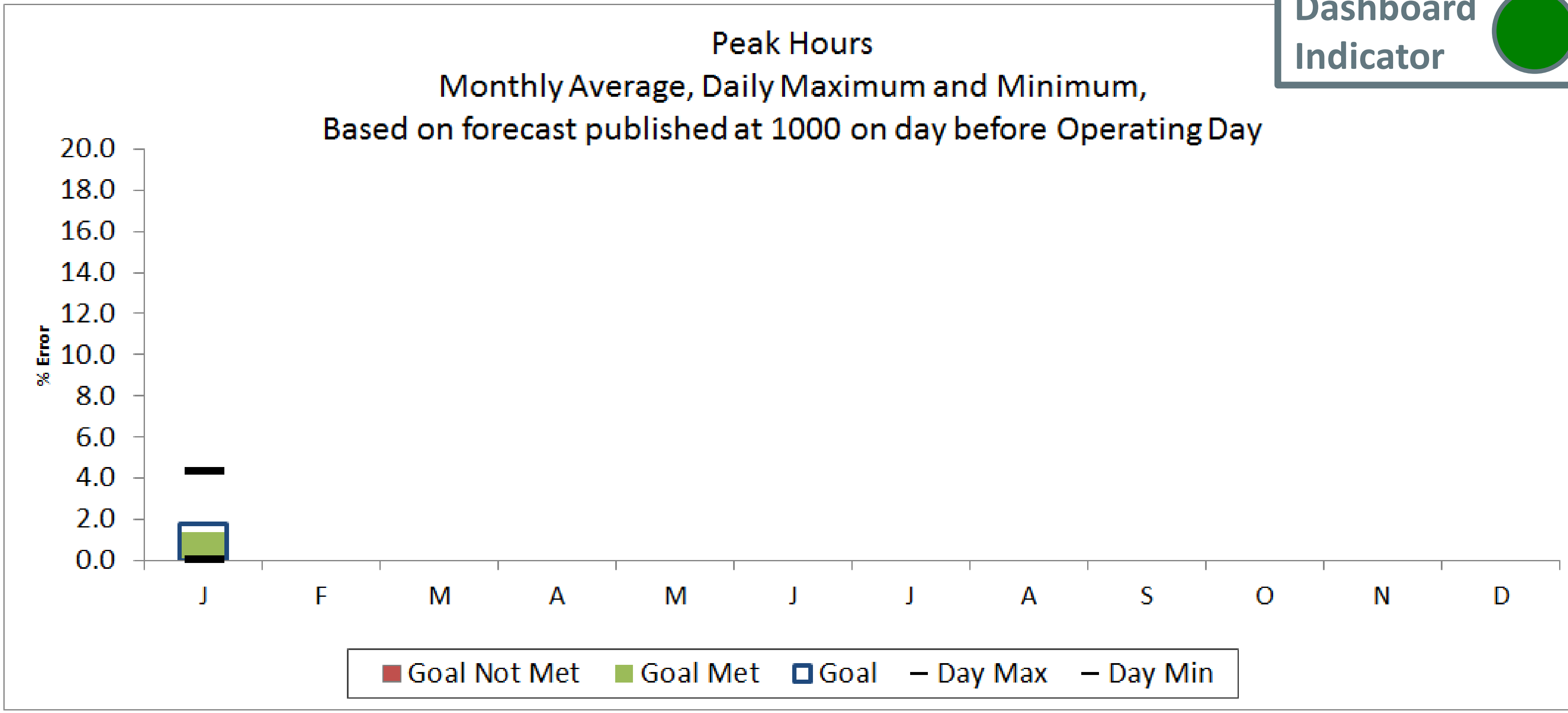
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.31												4.31
Day Min	0.46												0.46
MAPE	1.57												1.57
Goal	1.80												

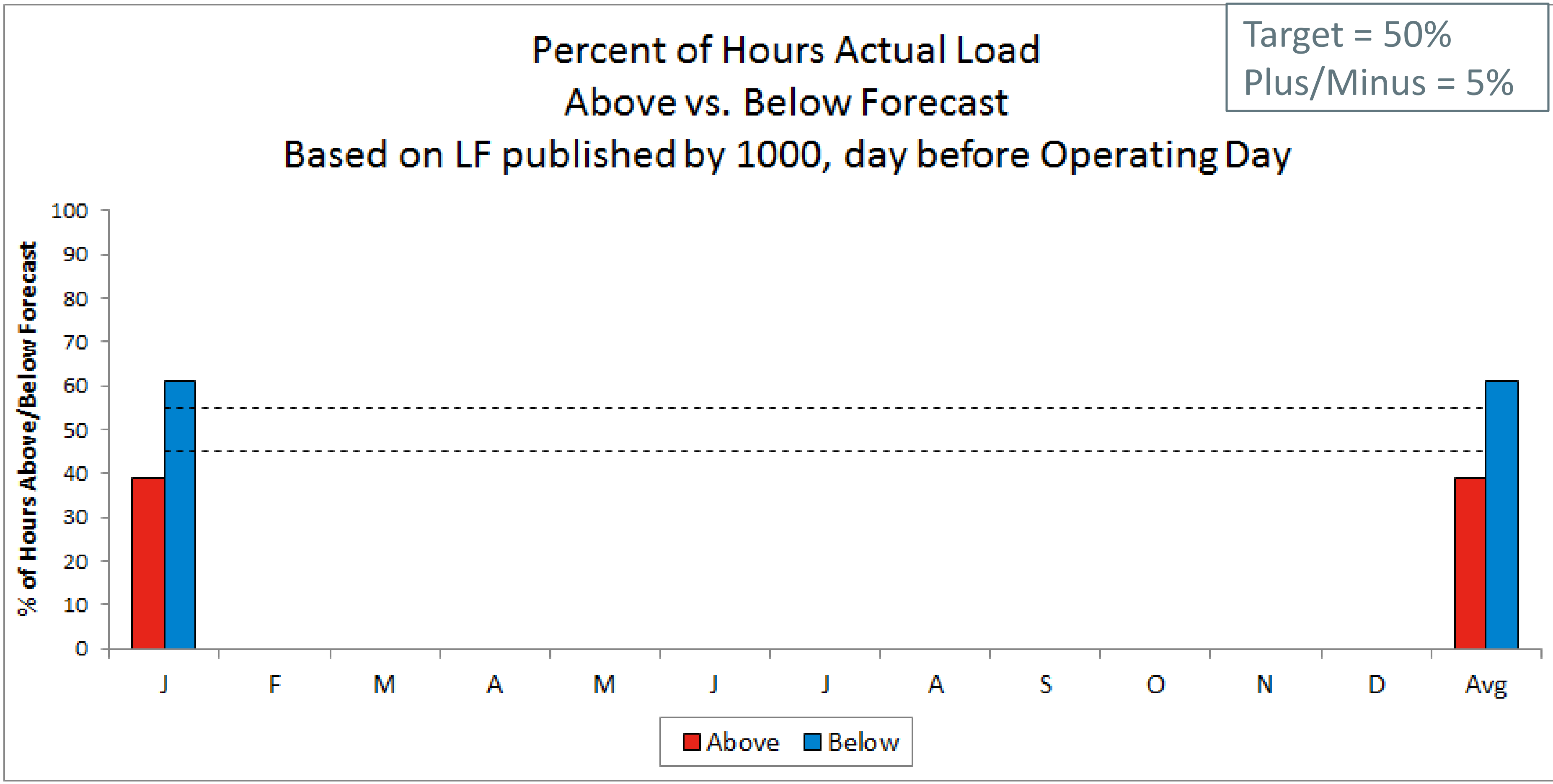
2020 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



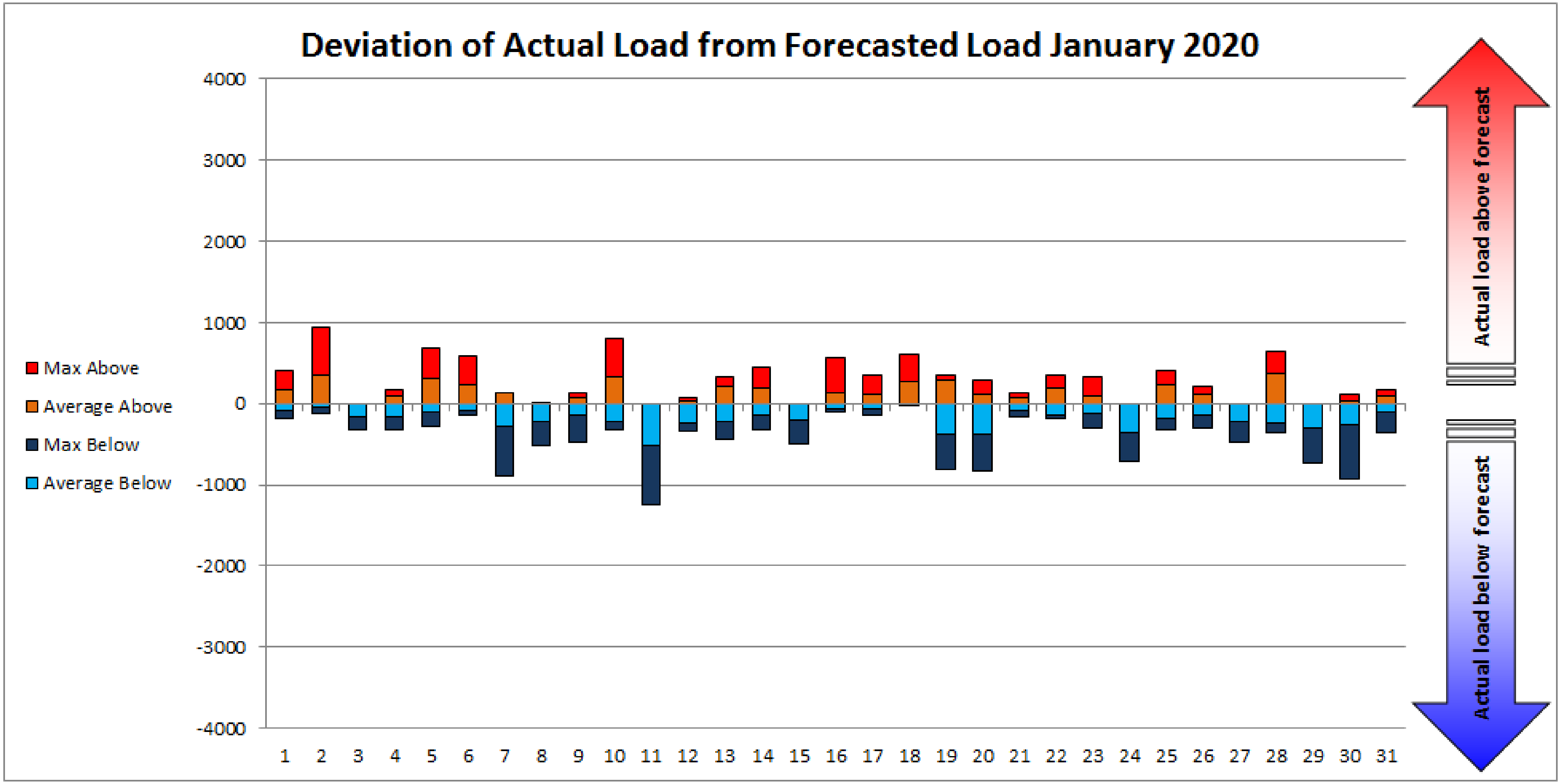
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.33												4.33
Day Min	0.07												0.07
MAPE	1.41												1.41
Goal	1.80												

2020 System Operations - Load Forecast Accuracy cont.

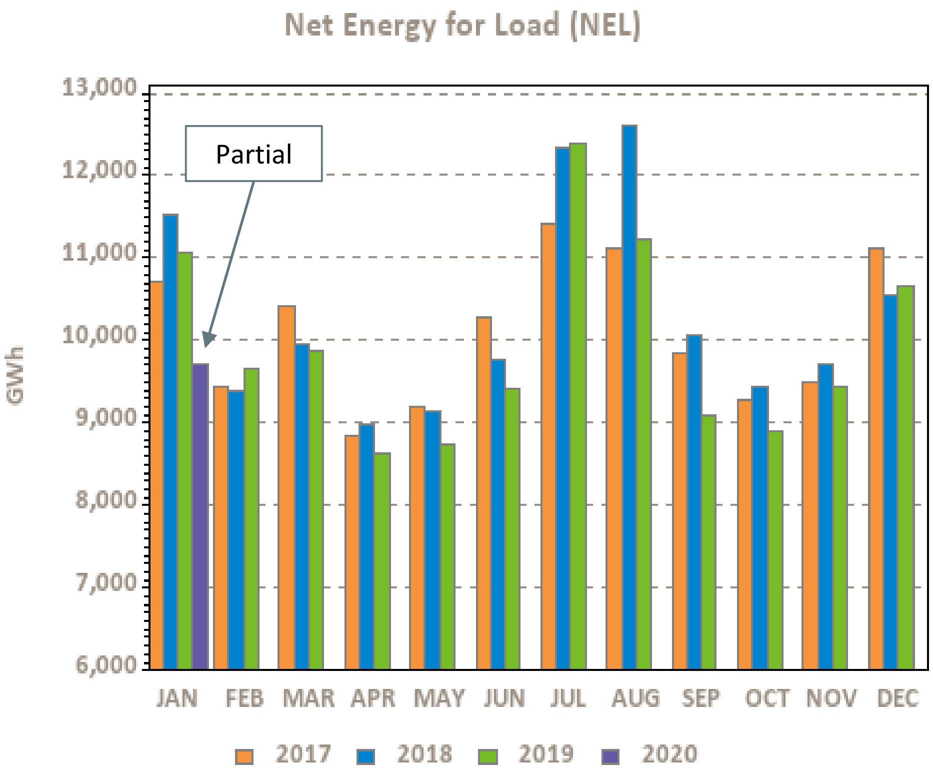


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	39												39
Below %	61												61
Avg Above	136.2												136
Avg Below	-192.4												-192
Avg All	-65												-65

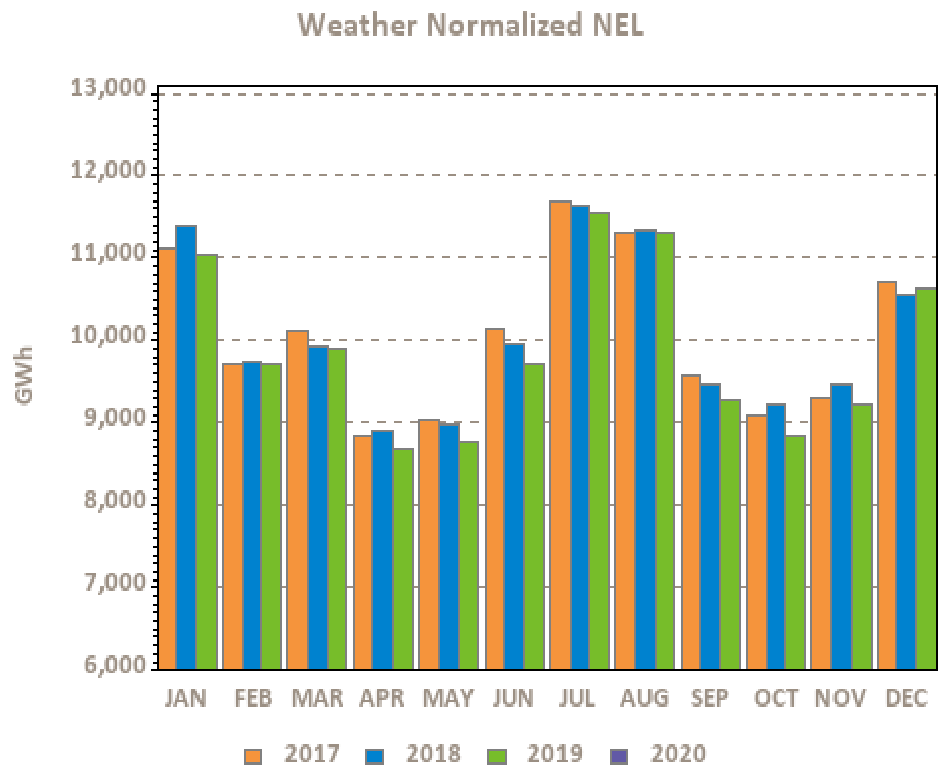
2020 System Operations - Load Forecast Accuracy cont.



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



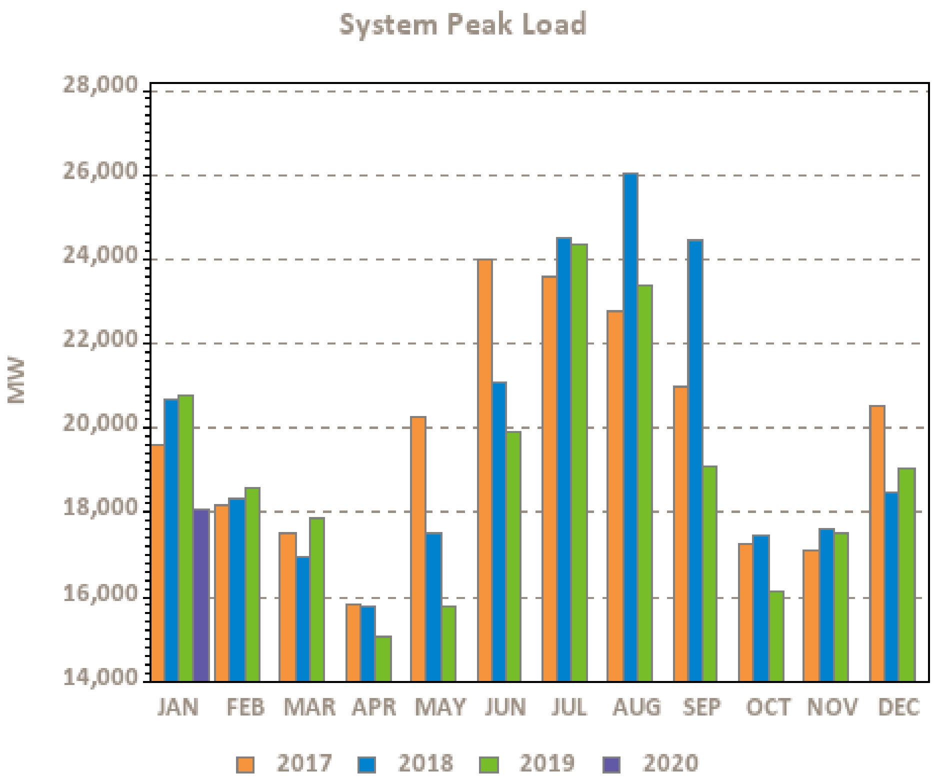
Ann Tot (TWh): 121.2 123.5 119.1 9.7



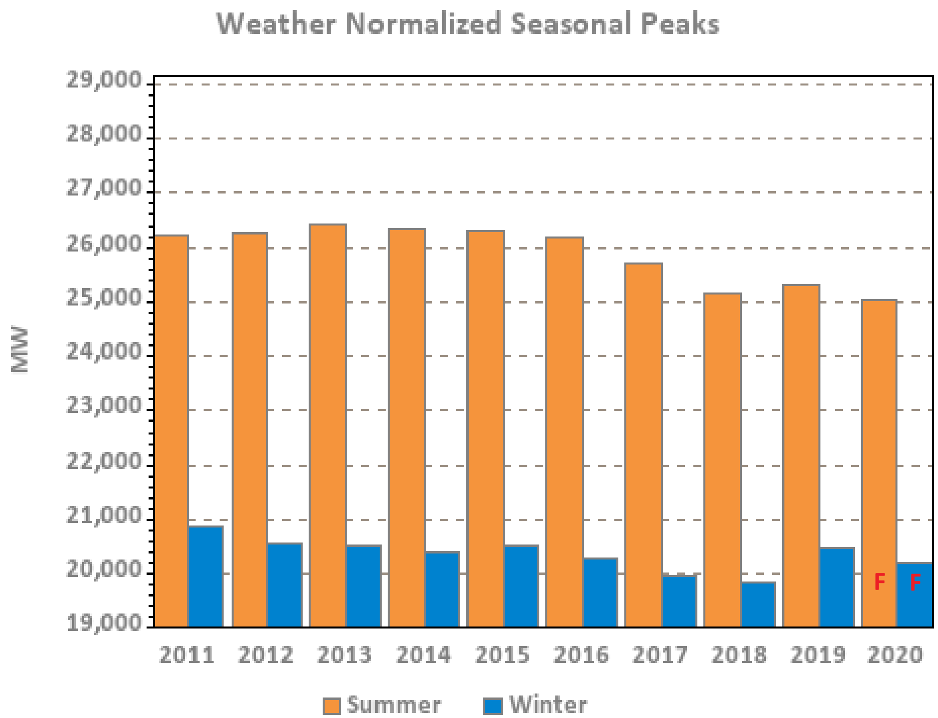
Ann Tot (TWh): 120.7 120.6 118.7 0

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

Monthly Peak Loads and Weather Normalized Seasonal Peak History



Revenue quality metered value

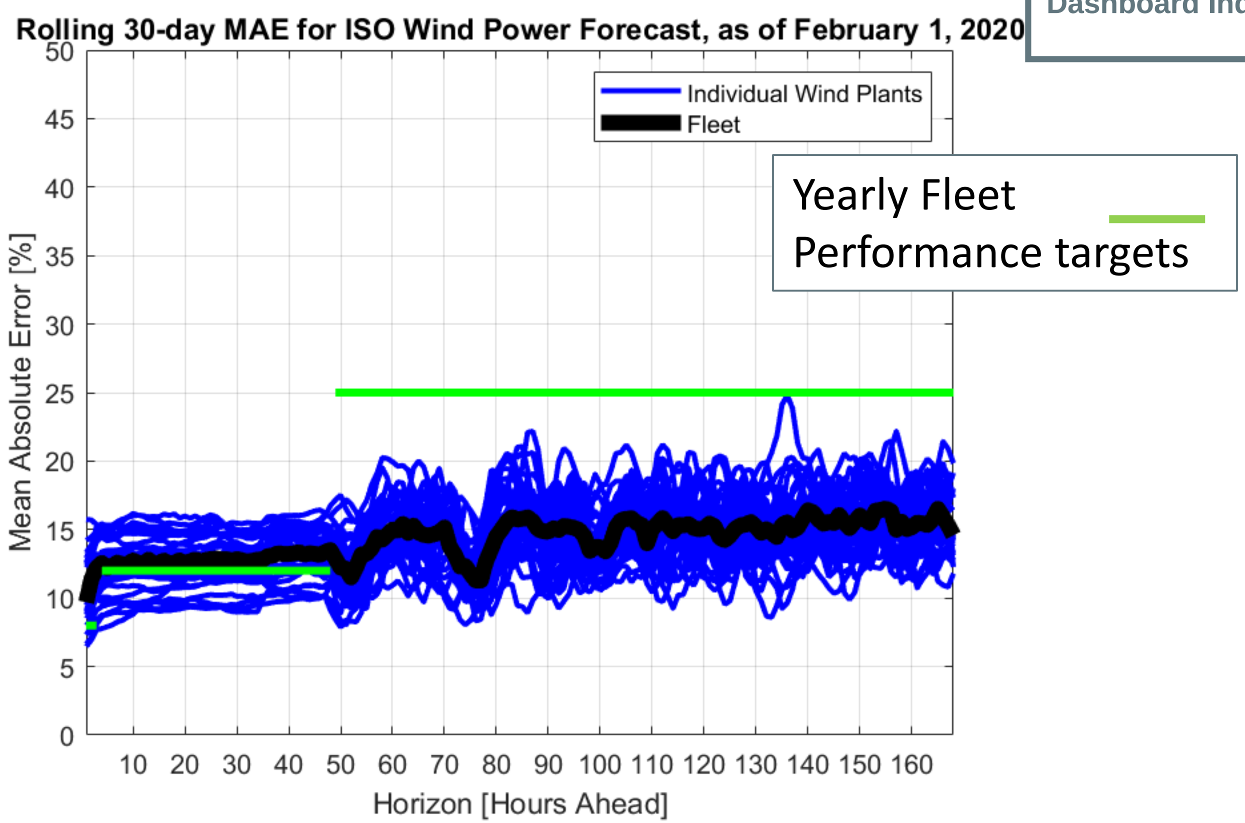


Winter beginning in year displayed

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

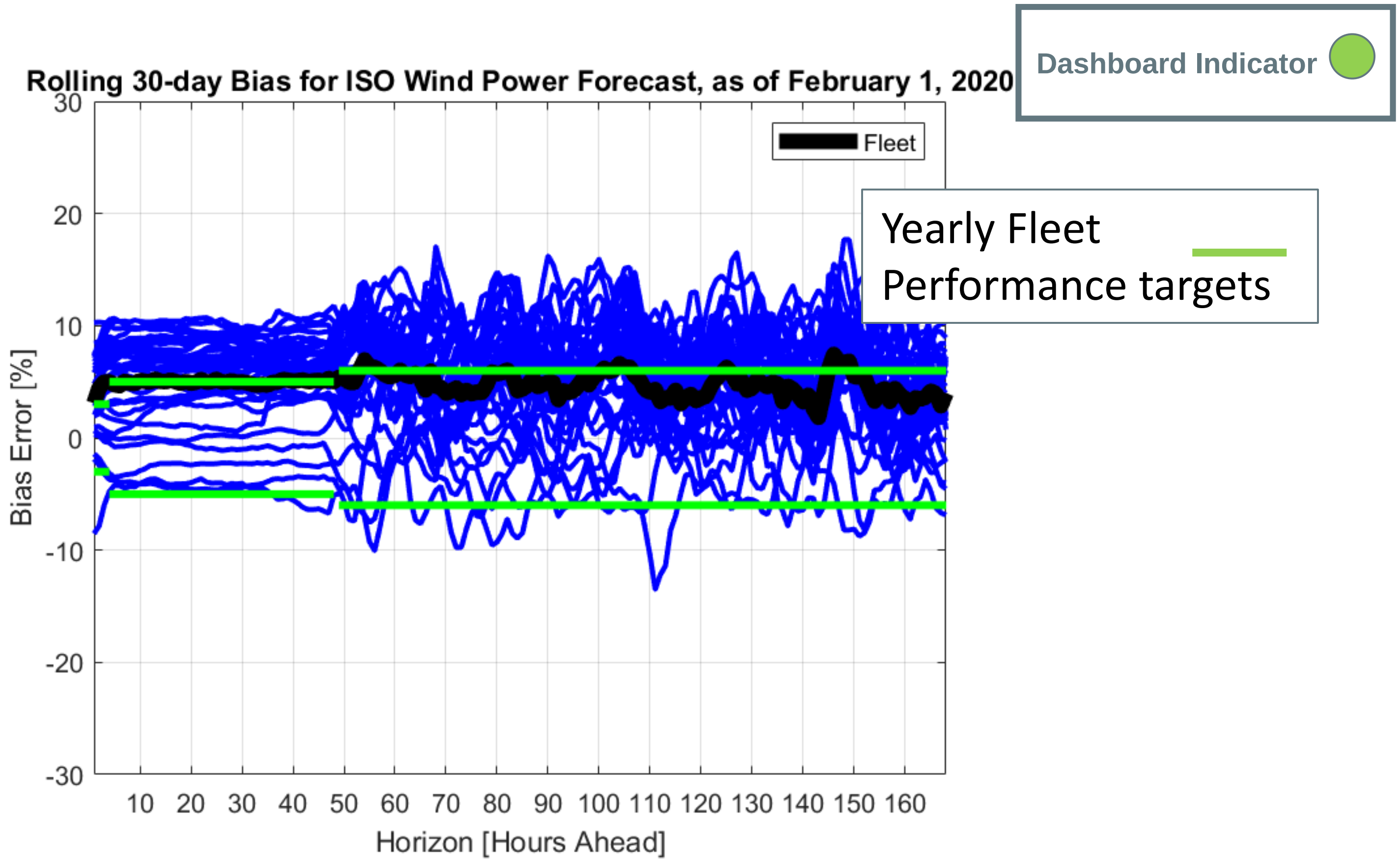
Wind Power Forecast Error Statistics: Medium and Long Term Forecasts MAE

Dashboard Indicator



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, except for hours 37 to 48, monthly MAE is within the yearly performance targets.

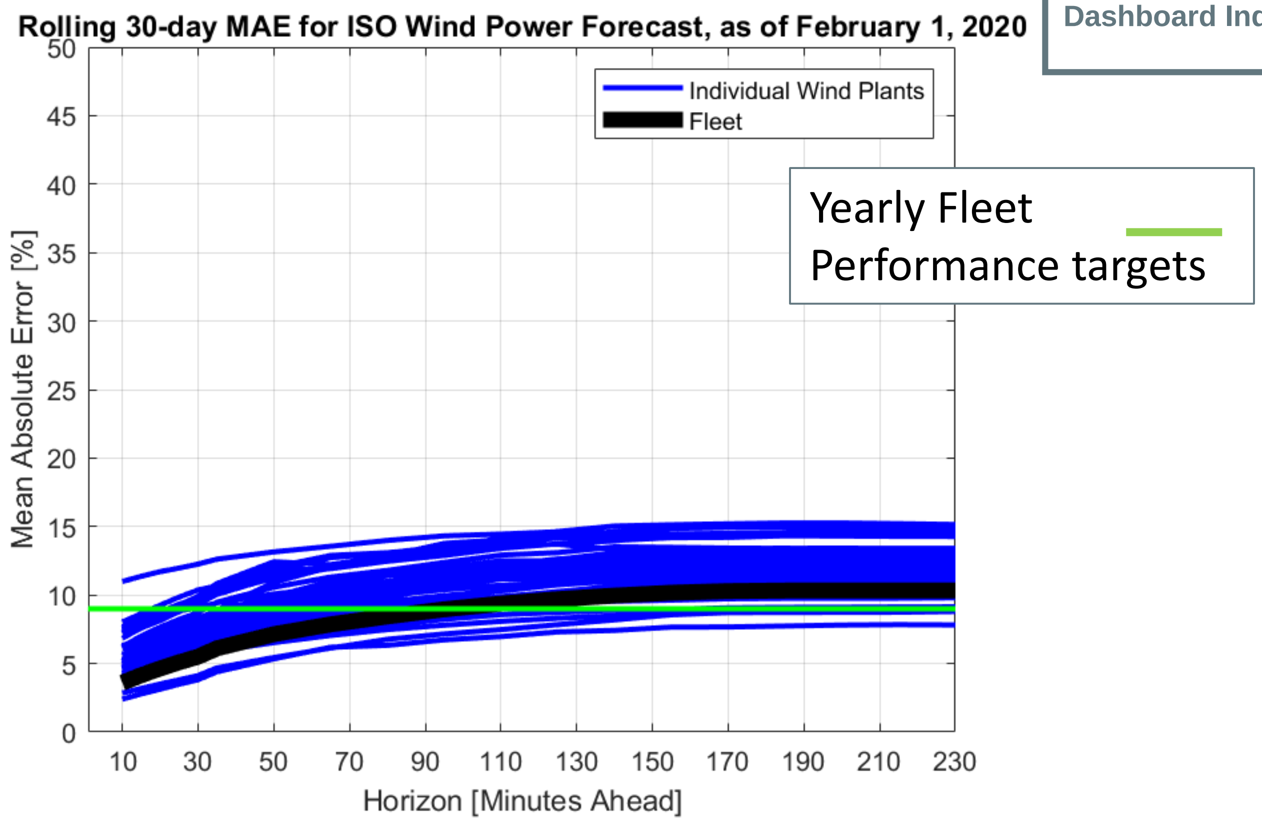
Wind Power Forecast Error Statistics: Medium and Long Term Forecasts Bias



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 mostly within yearly performance targets.

Wind Power Forecast Error Statistics: Short Term Forecast MAE

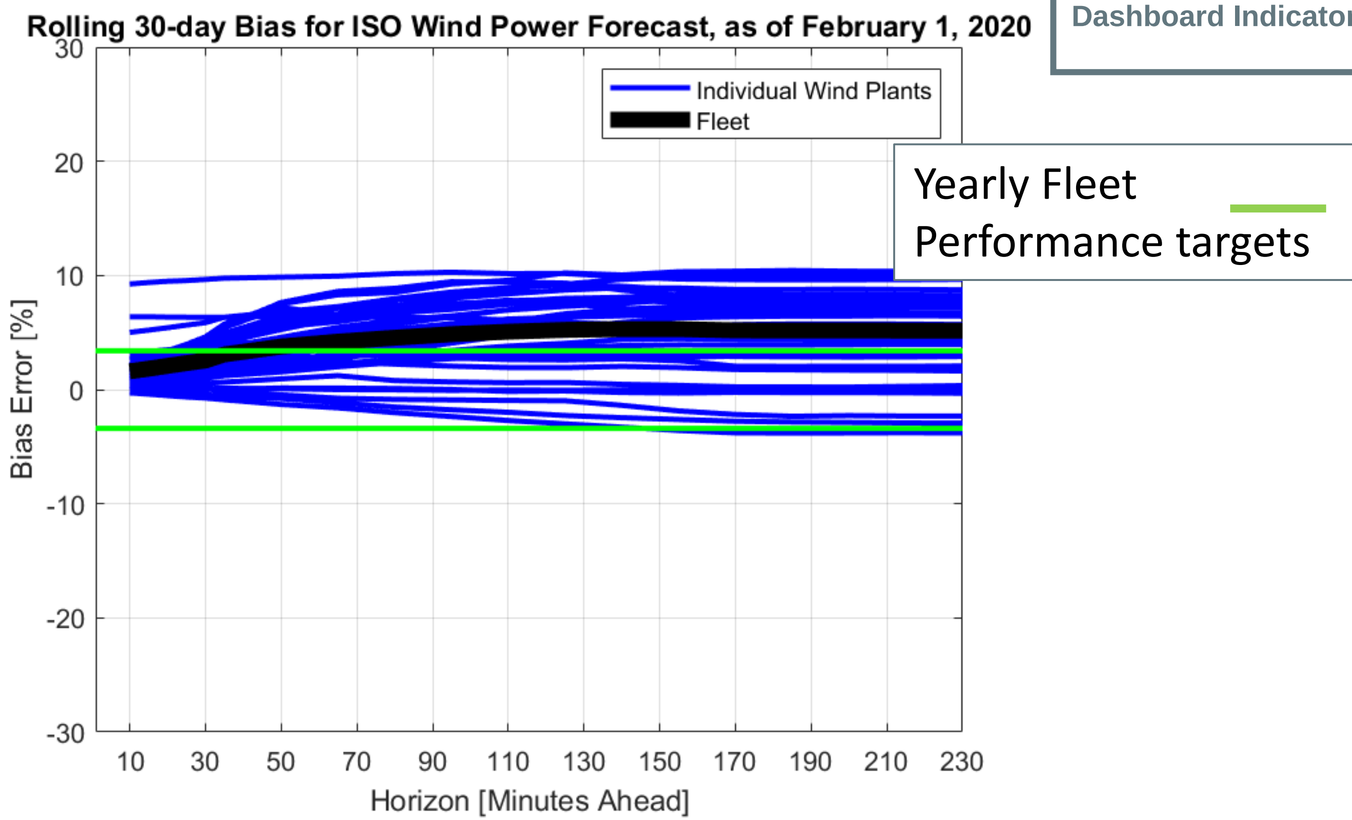
Dashboard Indicator



Ideally, MAE and Bias would be both equal to zero. As is typical, MAE increases with the forecast horizon. MAE and Bias for the fleet of wind power resources are less due to offsetting errors. Across all time frames, the ISO-NE/DNV-GL forecast is very good compared to industry standards, and, out to 3 hours ahead, monthly MAE is within the yearly performance targets out to 110 minutes.

Wind Power Forecast Error Statistics: Short Term Forecast Bias

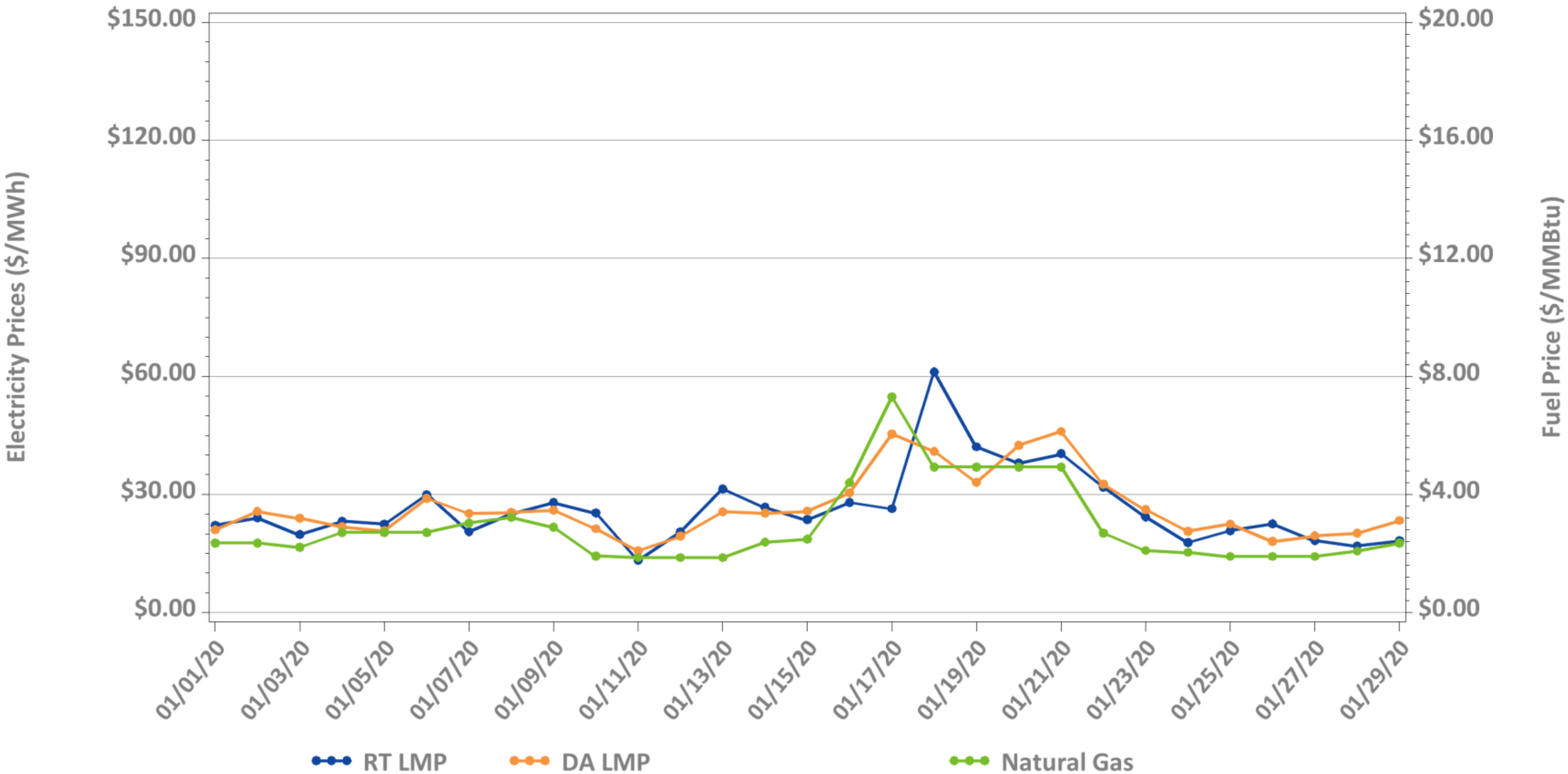
Dashboard Indicator



Ideally, MAE and Bias would be both equal to zero. Positive bias means less windpower was actually available compared to forecast. Negative bias means more windpower was actually available compared to forecast. Across all time frames, the ISO-NE/DNV-GL forecast compares well with industry standards, and monthly Bias is within yearly performance targets out to 70 minutes ahead.

MARKET OPERATIONS

Daily Average DA and RT ISO-NE Hub Prices and Input Fuel Prices: January 1-29, 2020

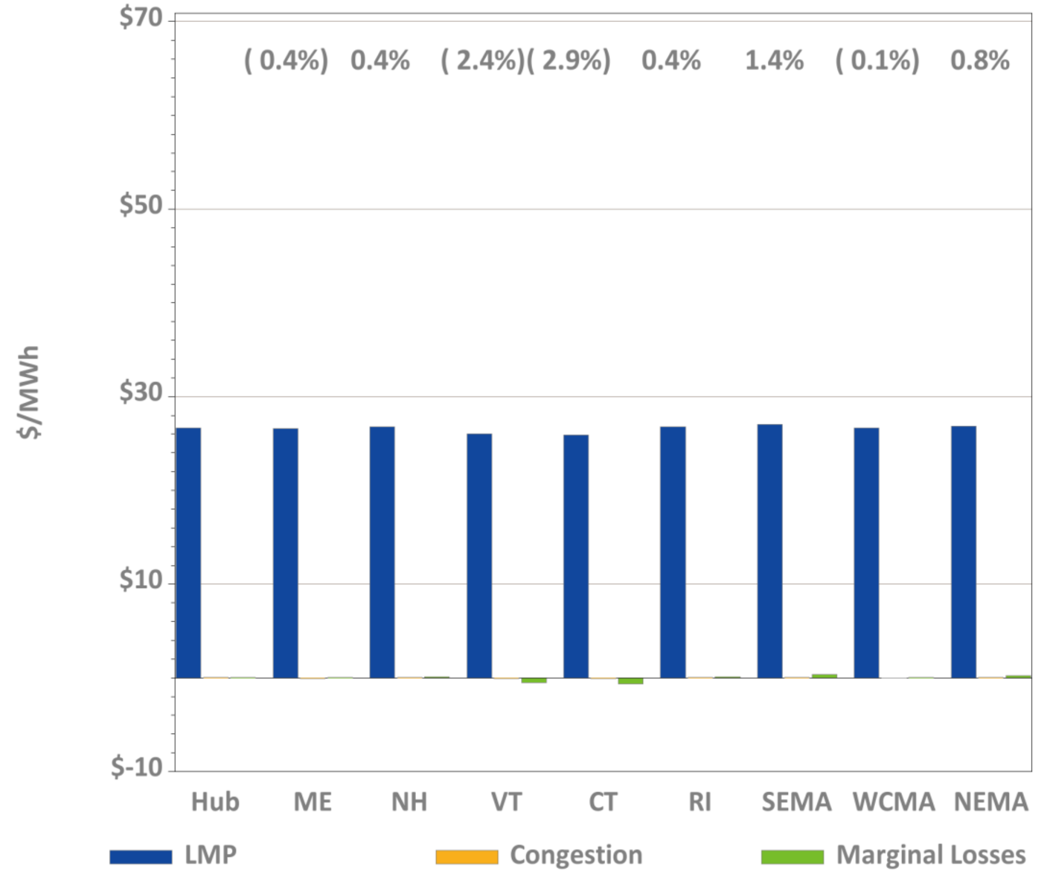


Underlying natural gas data furnished by:

ICE Global markets in clear view

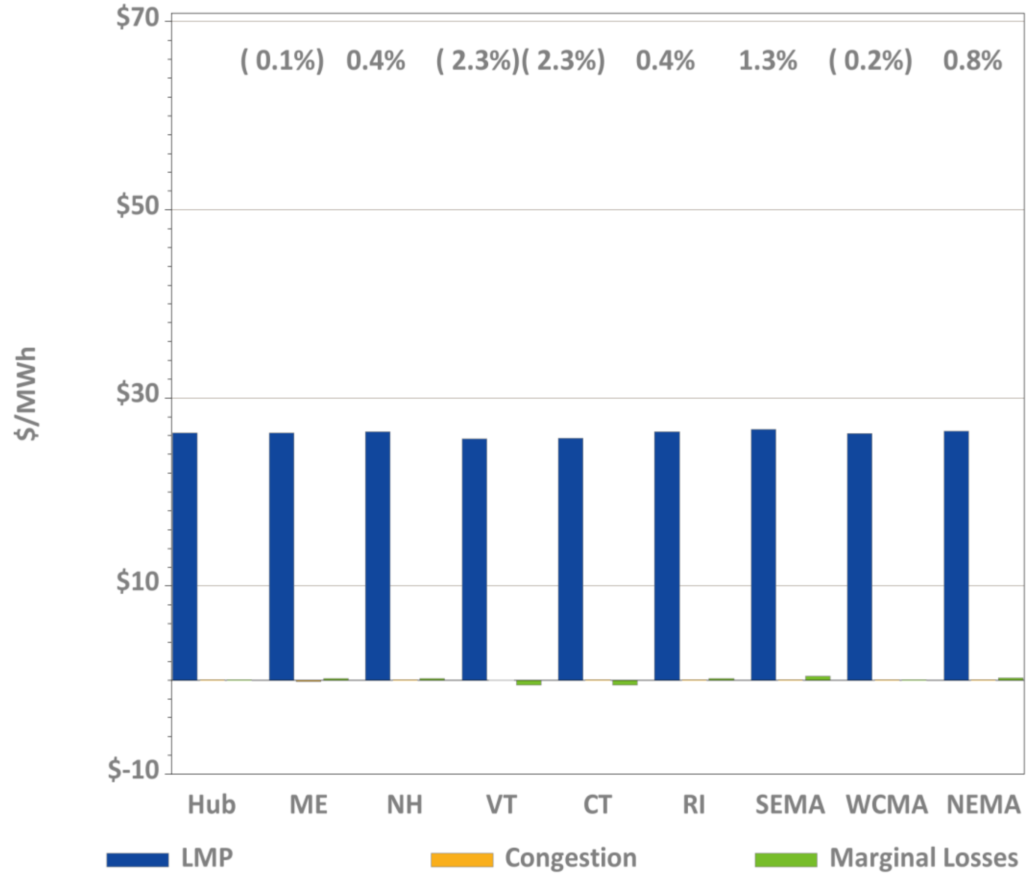
Average price difference over this period (DA-RT): $0.37
Average price difference over this period ABS(DA-RT): $4.04
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 15%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, January 2020



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

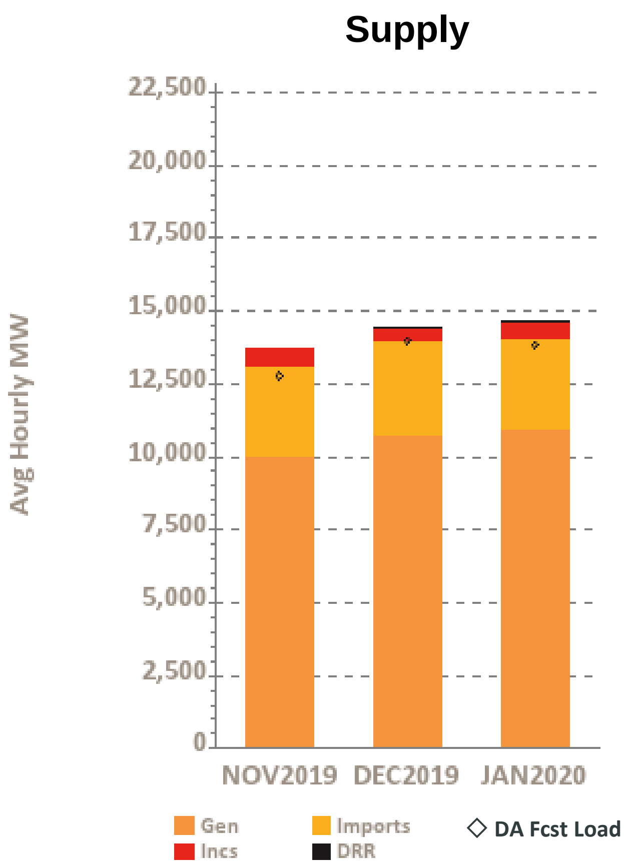
RT LMPs Average by Zone & Hub, January 2020

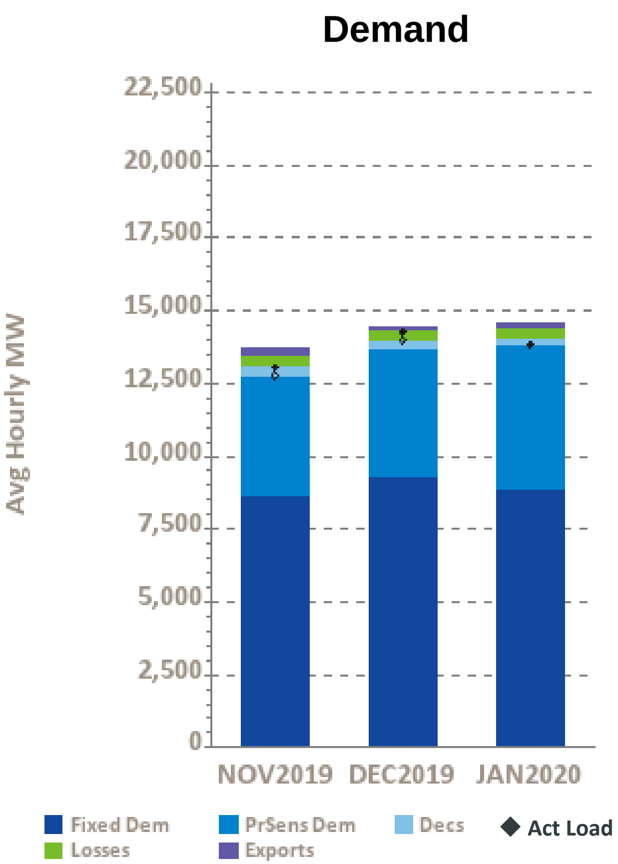


Definitions

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

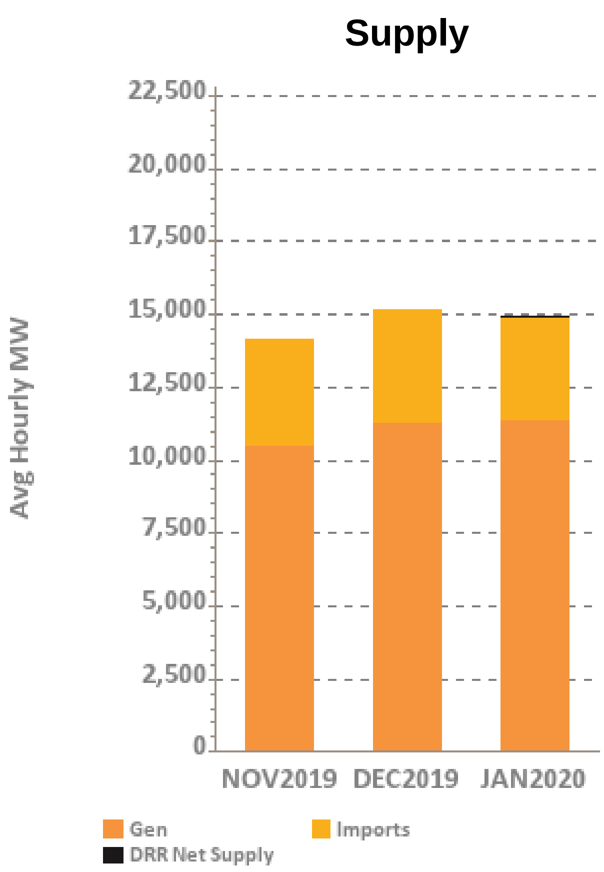


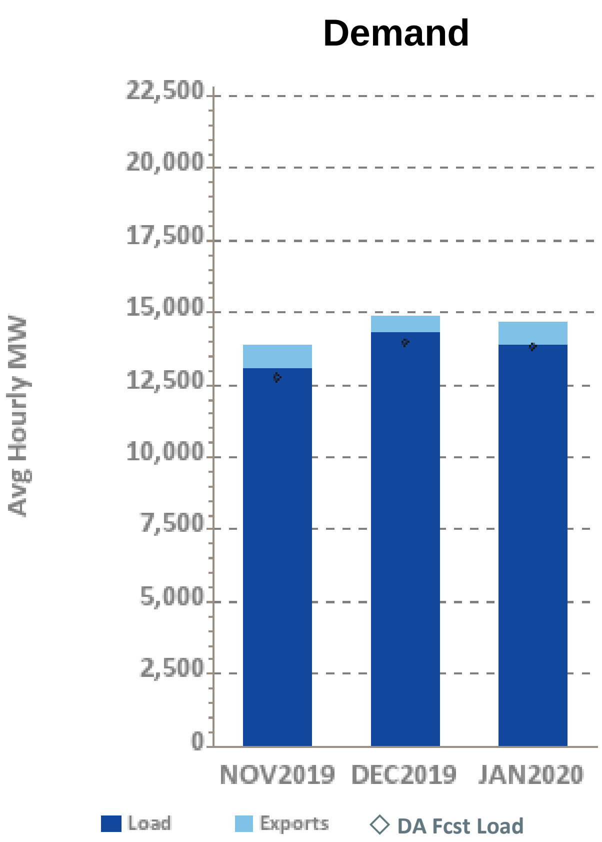


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load

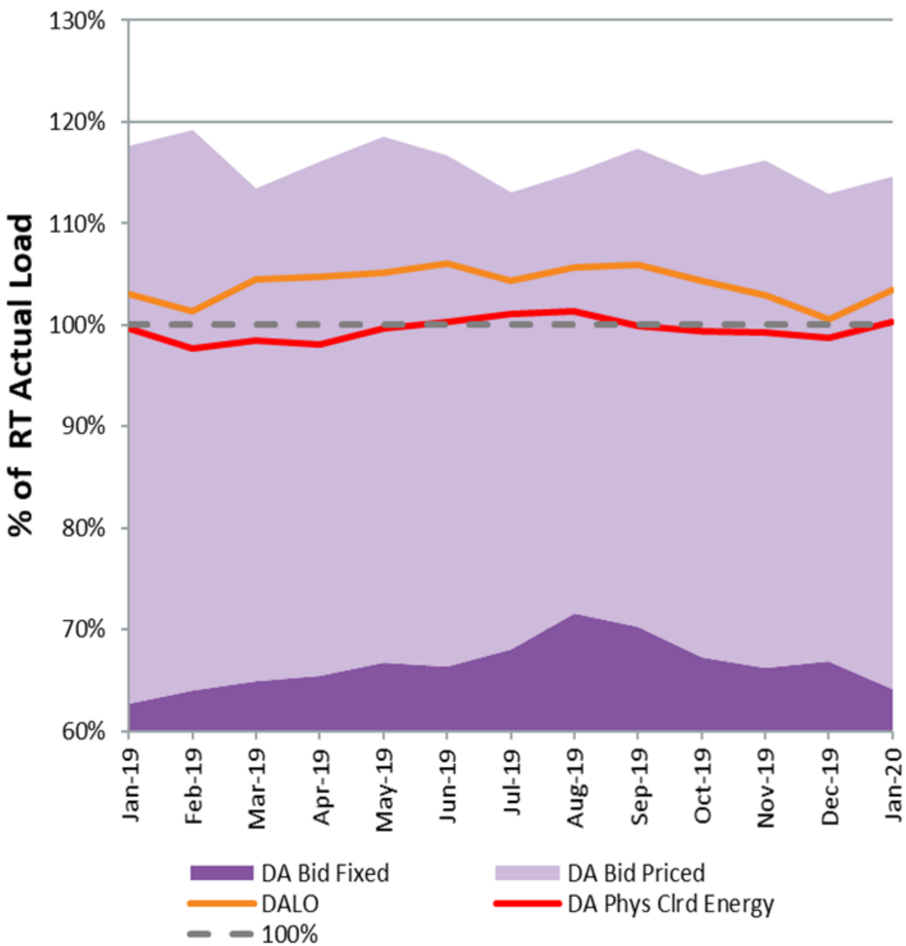
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

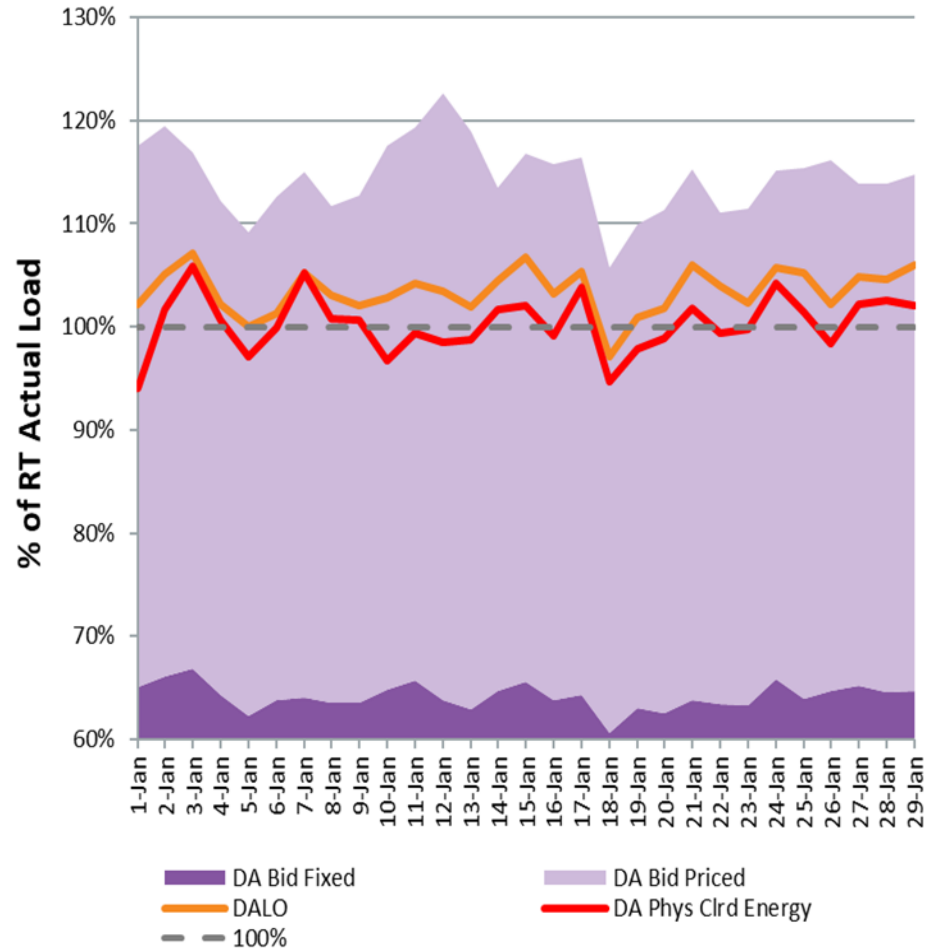
Components of RT Supply and Demand – Last Three Months





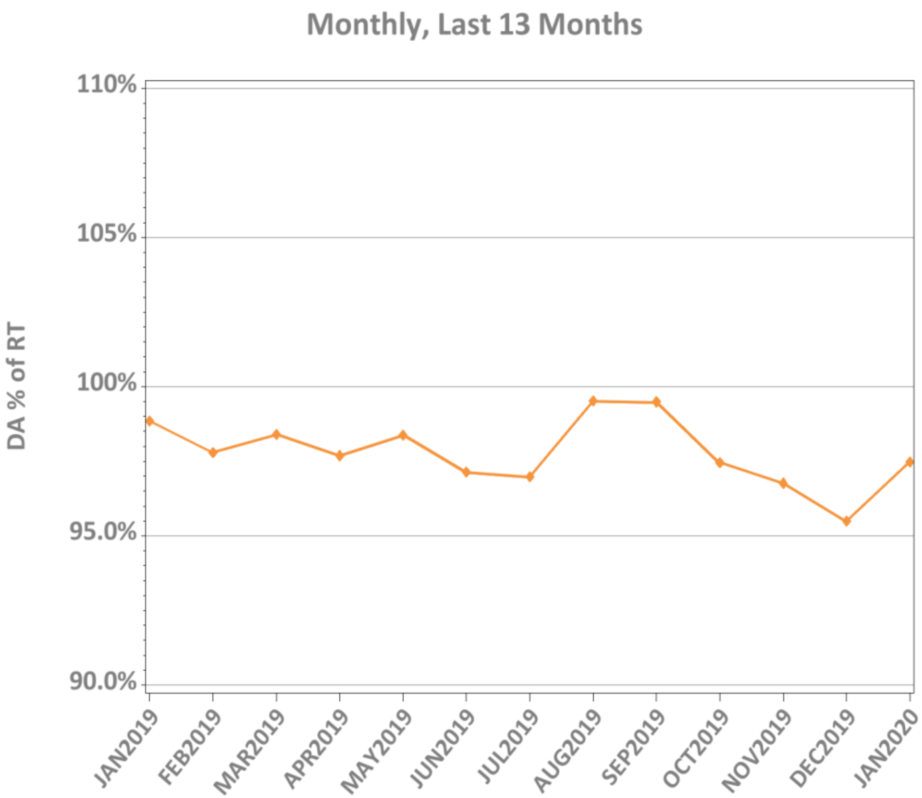
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

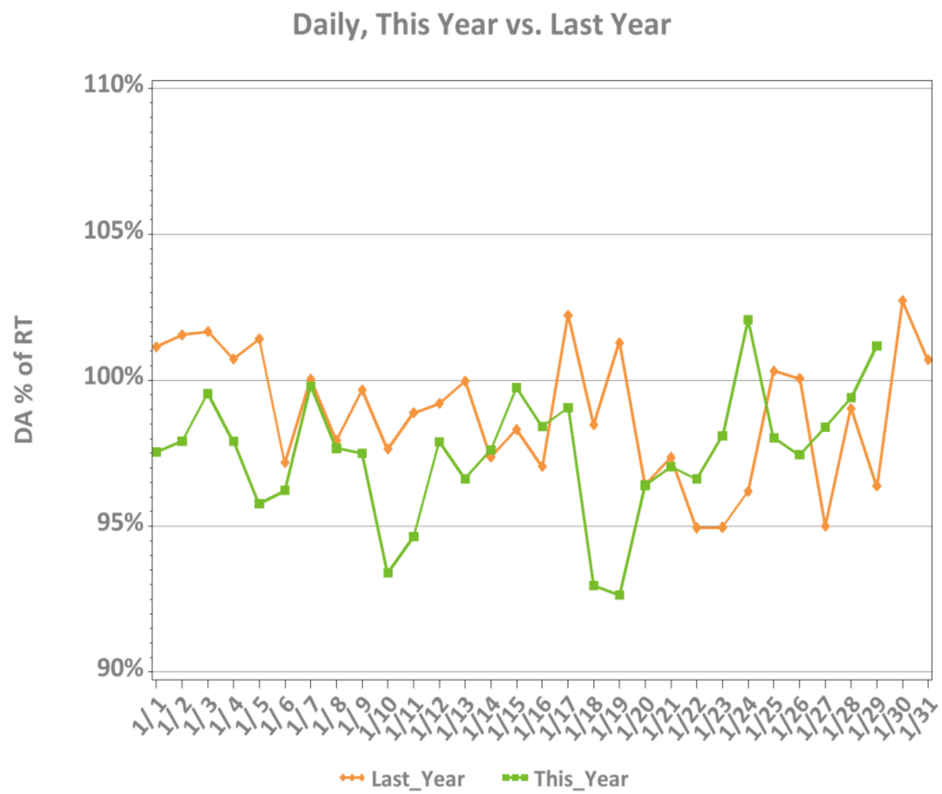




Note: Percentages were derived for the peak hour of each day (shown on right), then averaged over the month (shown on left). Values at hour of forecasted peak load. DA Bid categories reflect internal load asset bidding behavior (Virtual demand and export bid behavior not reflected).

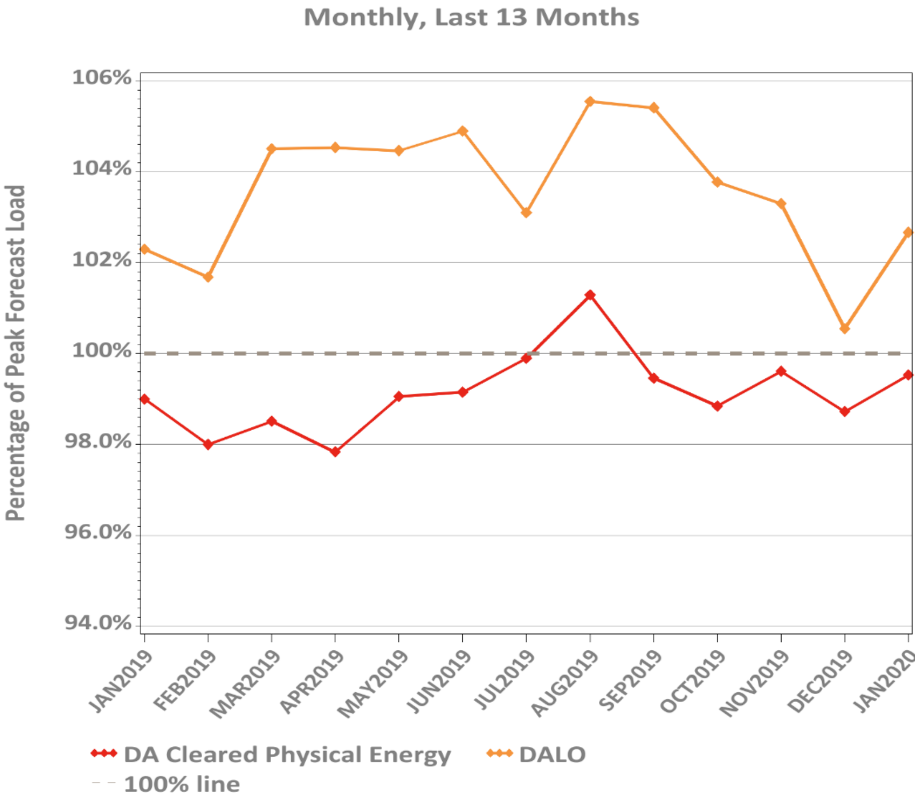
DA vs. RT Load Obligation: December, This Year vs. Last Year

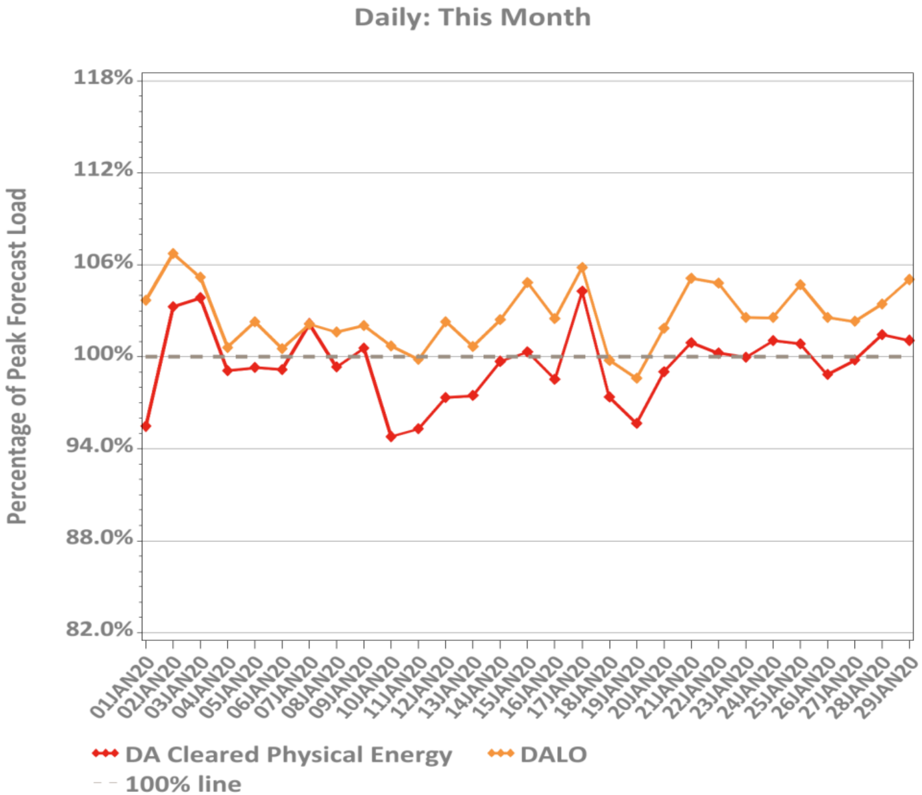




*Hourly average values

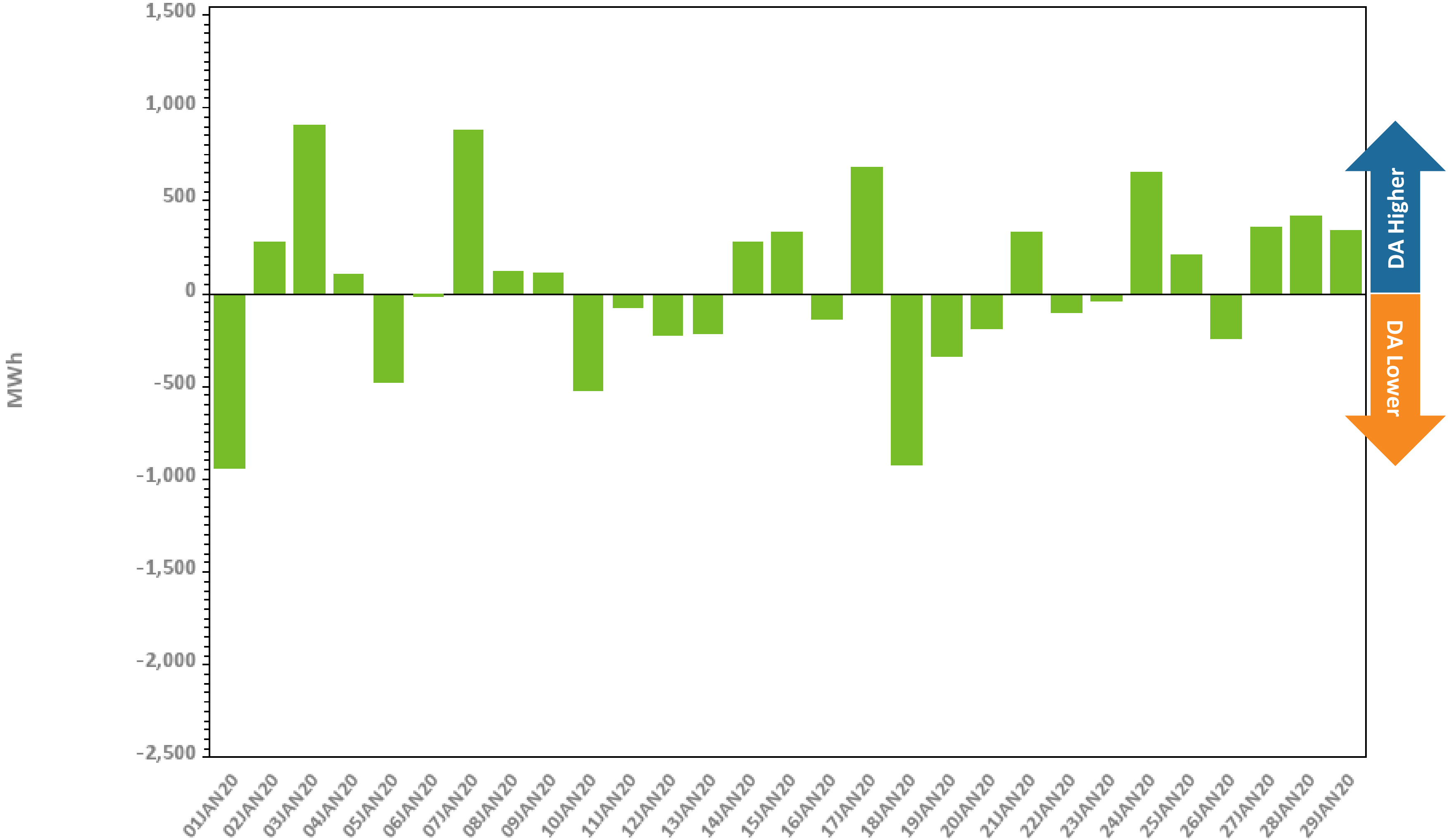
DA Volumes as % of Forecast in Peak Hour





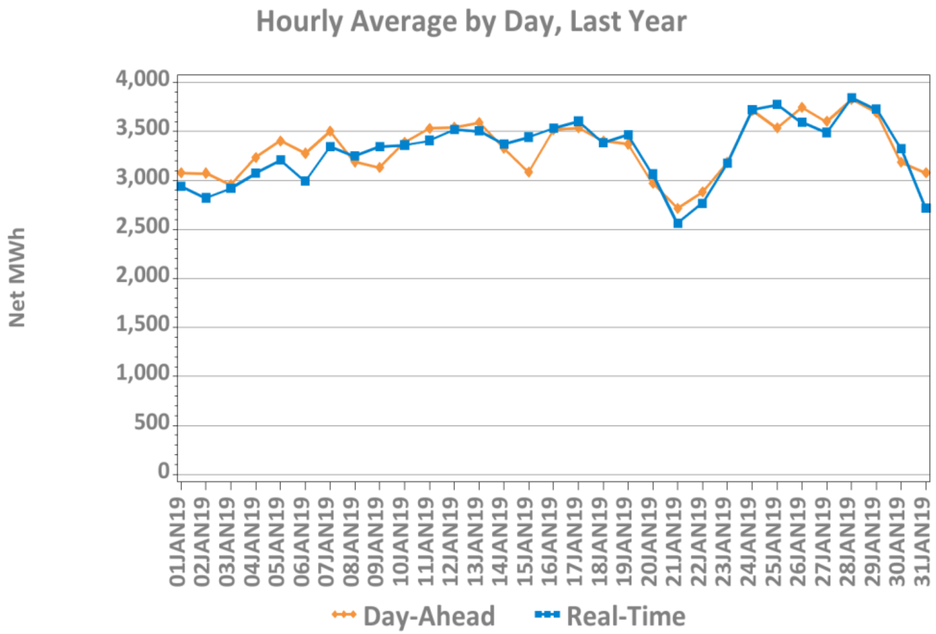
* There were *no* system-level supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) during January.

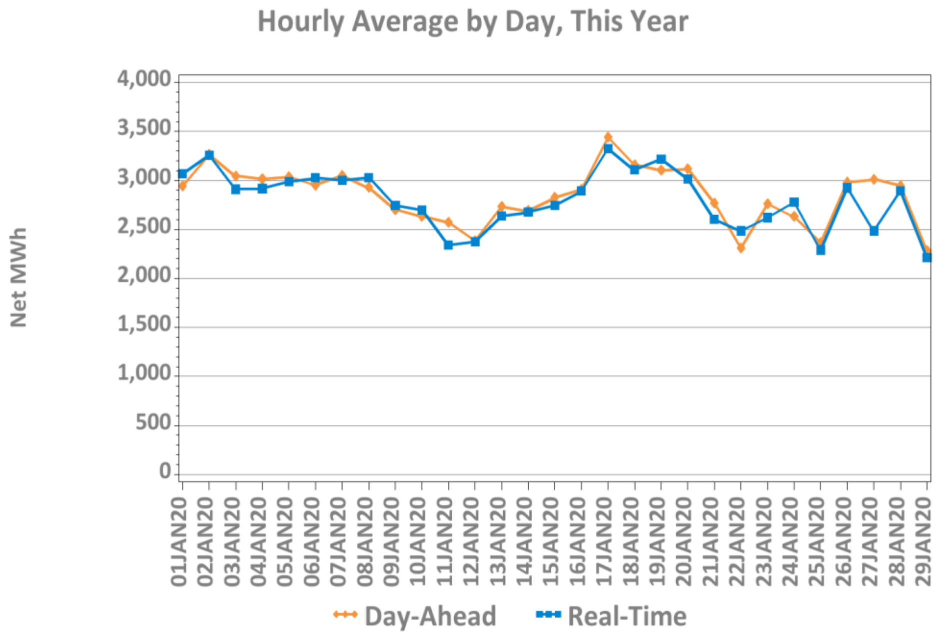
DA Cleared Physical Energy Difference from RT System Load at Peak Hour*



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

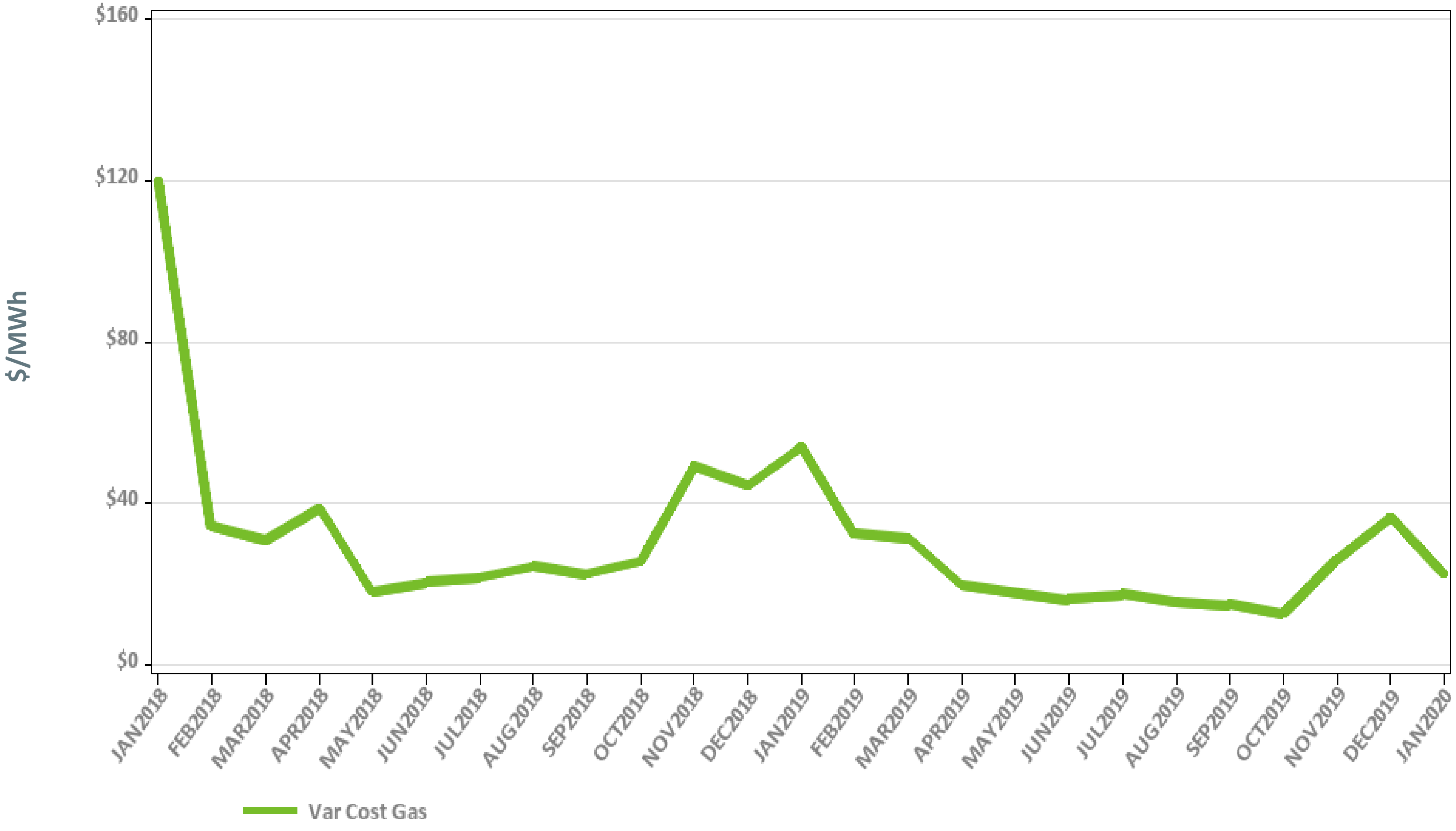
DA vs. RT Net Interchange January 2020 vs. January 2019





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

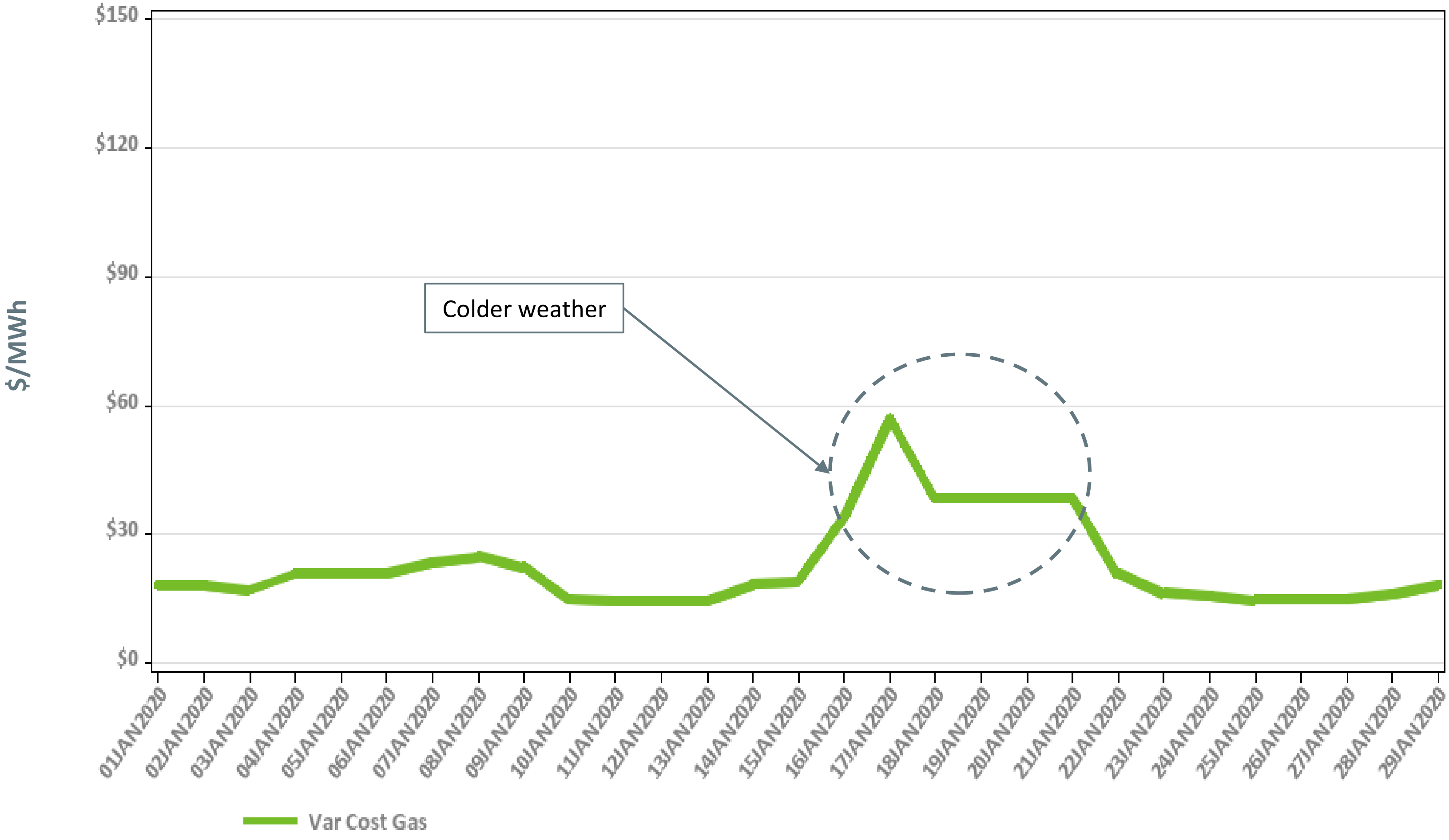


Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

Underlying natural gas data furnished by:

ice Global markets in clear view

Variable Production Cost of Natural Gas: Daily

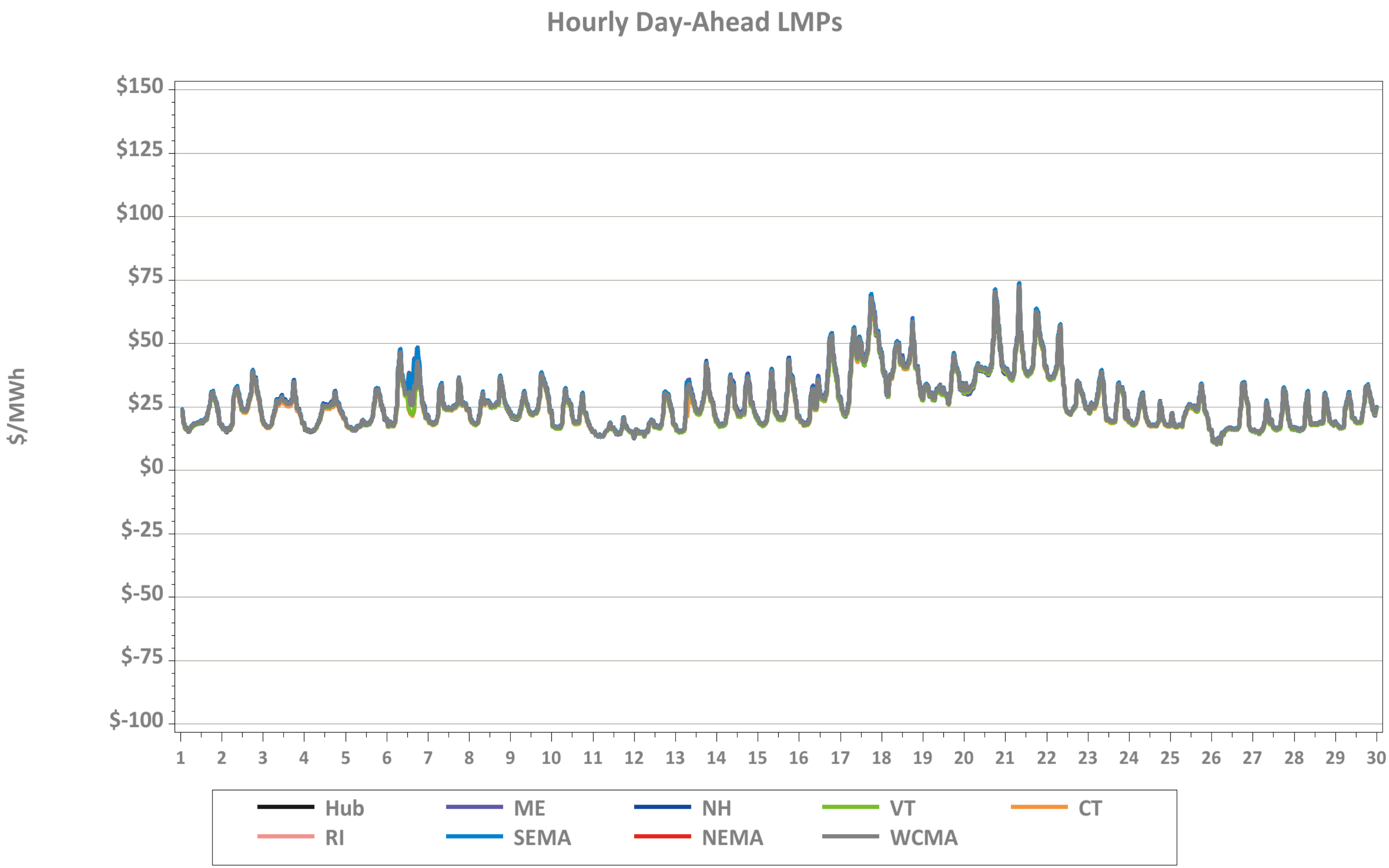


Underlying natural gas data furnished by:

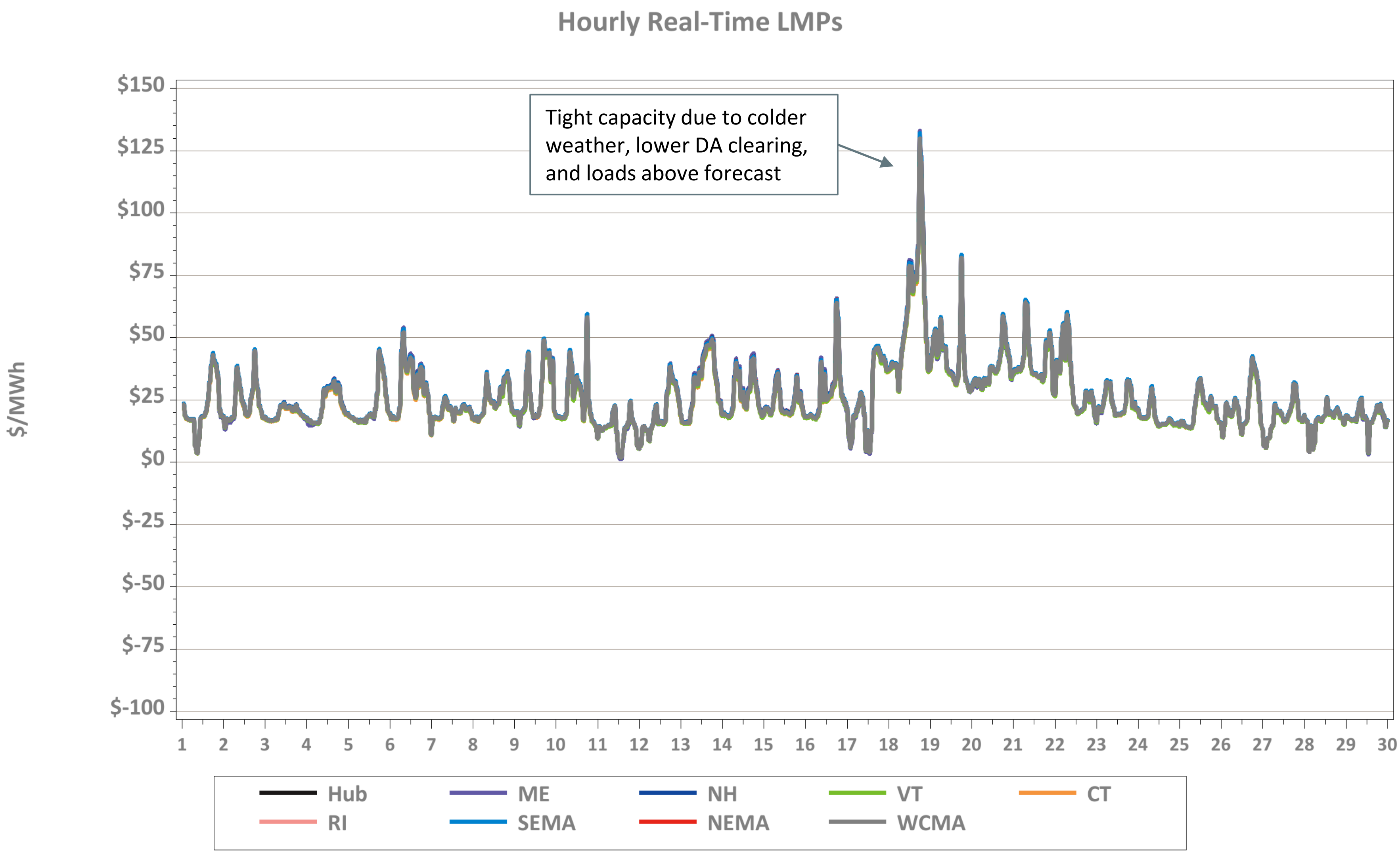
ICE Global markets in clear view

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

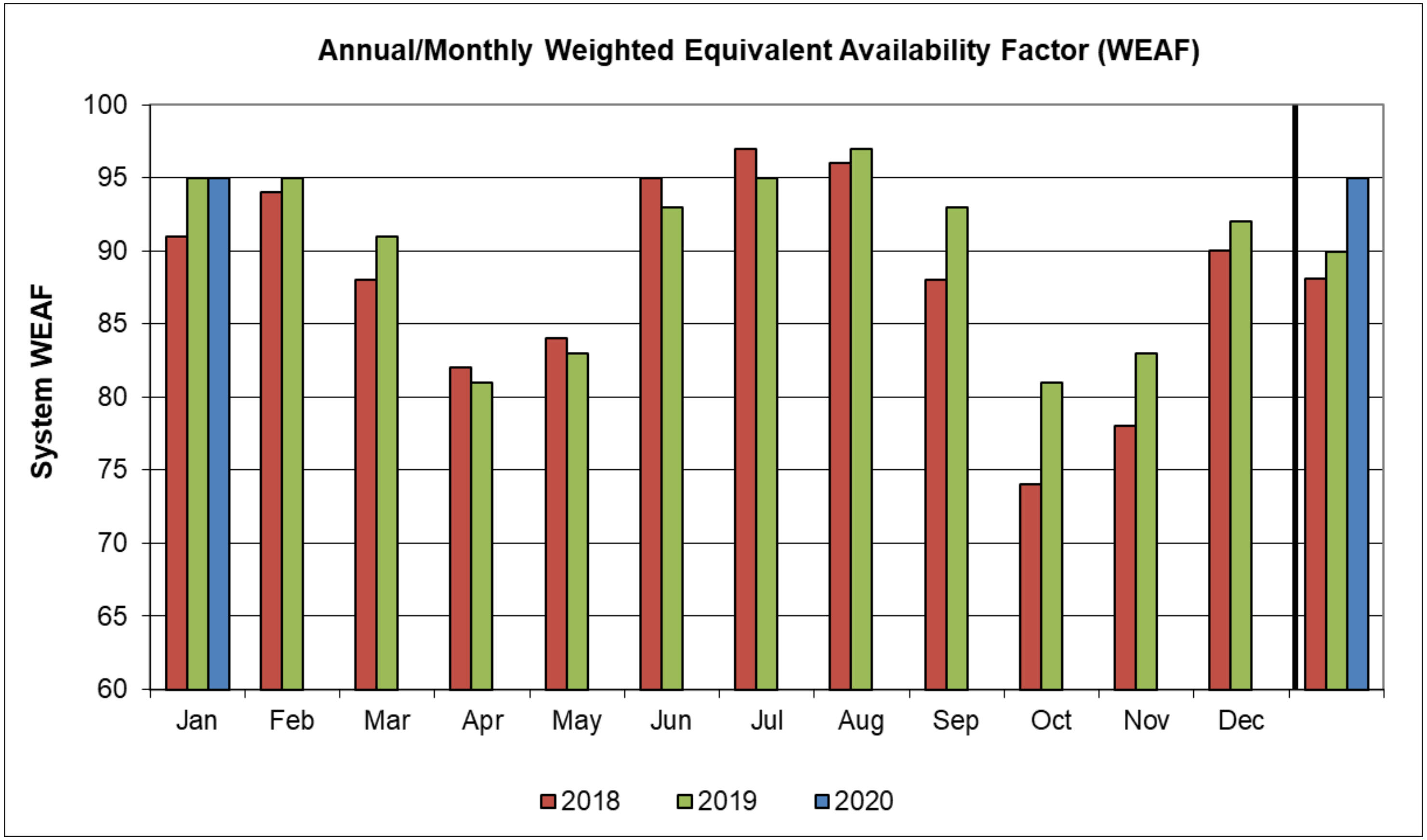
Hourly DA LMPs, January 1-29, 2020



Hourly RT LMPs, January 1-29, 2020



System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2020	95												95
2019	95	95	91	81	83	93	95	97	93	81	83	92	90
2018	91	94	88	82	84	95	97	96	88	74	78	90	88

Data as of 1/30/2020

BACK-UP DETAIL

DEMAND RESPONSE

Capacity Supply Obligation (CSO) MW by Demand Resource Type for February 2020

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	108.3	168.0	0.0	276.3
NH	27.4	115.4	0.0	142.8
VT	29.5	174.4	0.0	203.9
CT	99.2	77.4	437.6	614.2
RI	31.5	262.2	0.0	293.7
SEMA	38.7	411.2	0.0	449.9
WCMA	59.3	453.9	33.9	547.1
NEMA	50.9	637.3	0.0	688.1
Total	**444.7**	**2,299.6**	**471.5**	**3,215.9**

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

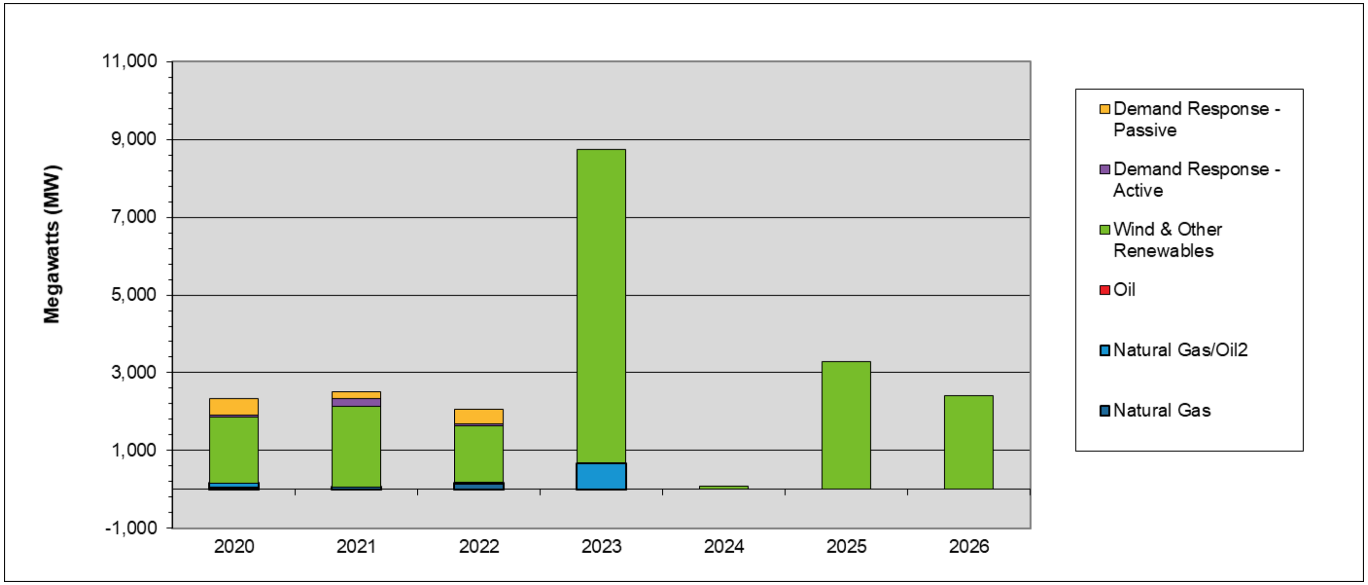
NEW GENERATION

New Generation Update
Based on Queue as of 1/31/20

- 4 projects totaling 278 MW applied for interconnection study since the last update
- 2 projects went commercial, 2 withdrew, and net decreases in project capacities resulted in a net decrease in new generation projects of 868 MW
- In total, 183 generation projects are currently being tracked by the ISO, totaling approximately 20,119 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



	2020	2021	2022	2023	2024	2025	2026	Total MW	% of Total[1]
Demand Response - Passive	422	184	380	0	0	0	0	986	4.6
Demand Response - Active	42	204	62	0	0	0	0	308	1.4
Wind & Other Renewables	1,707	2,068	1,450	8,071	80	3,276	2,400	19,052	88.9
Oil	0	0	0	0	0	0	0	0	0.0
Natural Gas/Oil[2]	121	0	39	672	0	0	0	832	3.9
Natural Gas	43	61	136	0	0	0	0	240	1.1
Totals	**2,336**	**2,517**	**2,067**	**8,743**	**80**	**3,276**	**2,400**	**21,419**	**100.0**

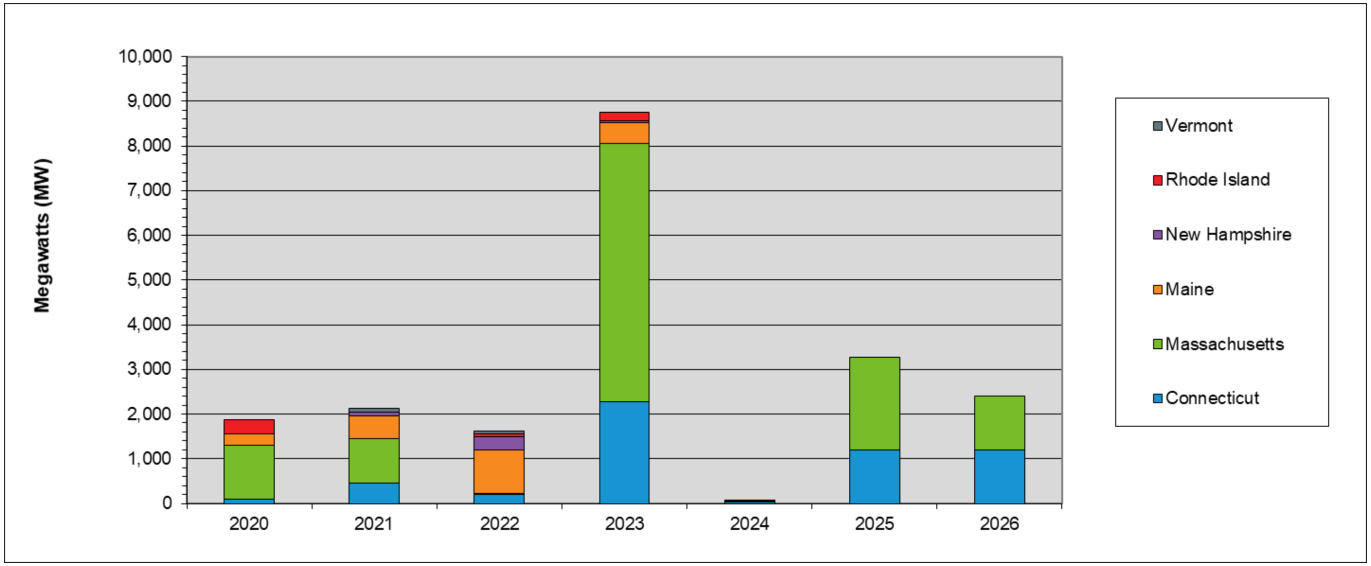
[1] Sum may not equal 100% due to rounding

[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



	2020	2021	2022	2023	2024	2025	2026	Total MW	% of Total[1]
Vermont	0	85	60	0	0	0	0	145	0.7
Rhode Island	312	6	73	180	0	0	0	571	2.8
New Hampshire	0	83	306	50	20	0	0	459	2.3
Maine	248	513	972	451	20	0	0	2,204	11.0
Massachusetts	1,211	990	16	5,780	0	2,076	1,200	11,273	56.0
Connecticut	100	452	198	2,282	40	1,200	1,200	5,472	27.2
Totals	**1,871**	**2,129**	**1,625**	**8,743**	**80**	**3,276**	**2,400**	**20,124**	**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	57	0	0	2	57
Battery Storage	15	2,115	0	0	15	2,115
Hydro	2	71	1	66	1	5
Landfill Gas	0	0	0	0	0	0
Natural Gas	8	240	0	0	8	240
Natural Gas/Oil	6	832	1	45	5	787
Nuclear	1	37	0	0	1	37
Oil	0	0	0	0	0	0
Solar	128	3,543	4	111	124	3,432
Wind	21	13,224	0	0	21	13,224
Total	183	20,119	6	222	177	19,897

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

New Generation Projection

By Operating Type

	Total		Green		Yellow	
Operating Type	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	9	217	0	0	9	217
Intermediate	2	116	0	0	2	116
Peaker	151	6,562	6	222	145	6,340
Wind Turbine	21	13,224	0	0	21	13,224
Total	183	20,119	6	222	177	19,897

- 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	57	2	57	0	0	0	0	0	0
Battery Storage	15	2,115	0	0	0	0	15	2,115	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	8	240	5	118	2	116	1	6	0	0
Natural Gas/Oil	6	832	0	0	0	0	6	832	0	0
Nuclear	1	37	1	37	0	0	0	0	0	0
Oil	0	0	0	0	0	0	0	0	0	0
Solar	128	3,543	0	0	0	0	128	3,543	0	0
Wind	21	13,224	0	0	0	0	0	0	21	13,224
Total	183	20,119	9	217	2	116	151	6,562	21	13,224

- 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	594.551	153.33		
	Passive Demand	2,791.02	2,835.354	44.334	2,883.767	48.413		
Demand Total		**3,210.95**	**3,276.575**	**65.625**	**3,478.318**	**201.743**		
Generator	*Non-Intermittent*	30,494.80	30,064.23	-430.569	30,159.891	95.661		
	Intermittent	894.217	823.796	-70.421	809.571	-14.225		
Generator Total		**31,389.02**	**30,888.03**	**-500.993**	**30,969.462**	**81.432**		
Import Total		**1,235.40**	**1,622.037**	**386.637**	**1,609.844**	**-12.193**		
****Grand Total**		**35,835.37**	**35,786.64**	**-48.731**	**36,057.624**	**270.984**		
Net ICR (NICR)		**34,075**	**33,660**	**-415**	**33,520**	**-140**		

* 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				
Demand	*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				
Generator	*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

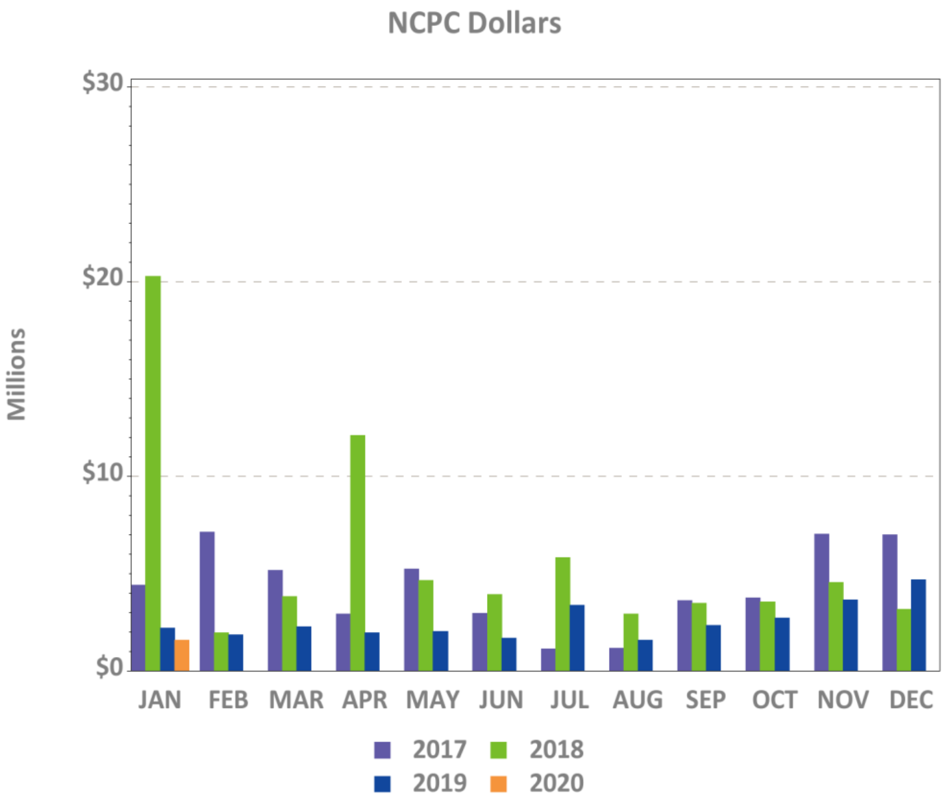
Definitions

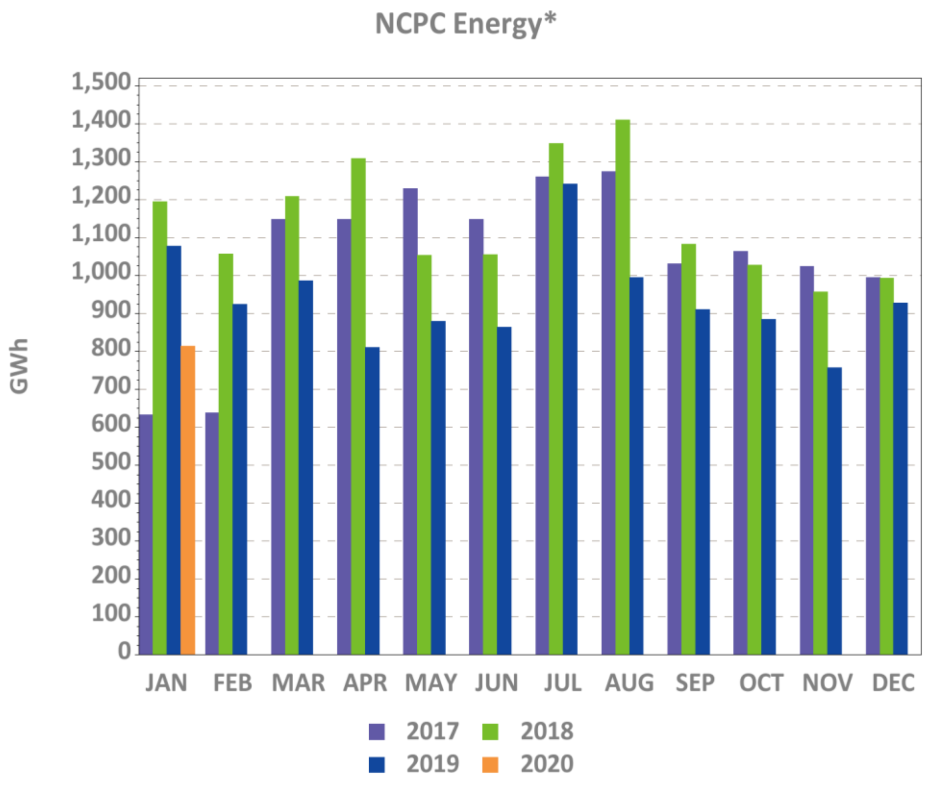
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing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

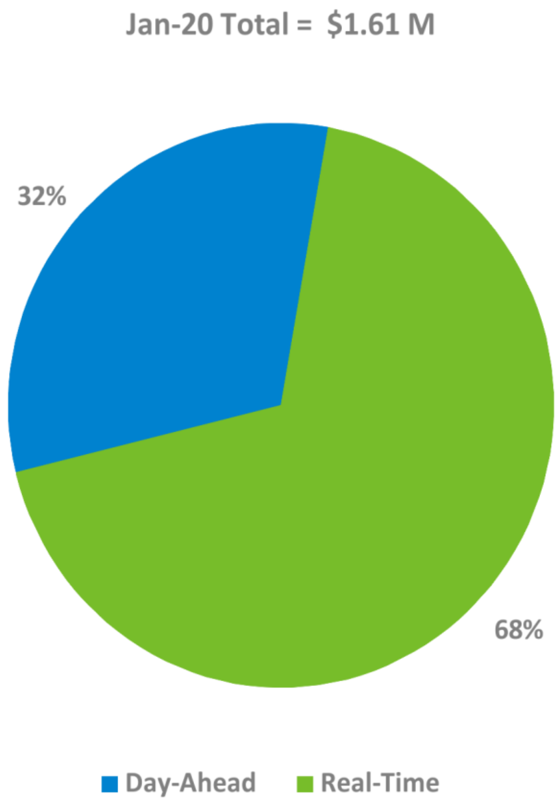
Year-Over-Year Total NCPC Dollars and Energy



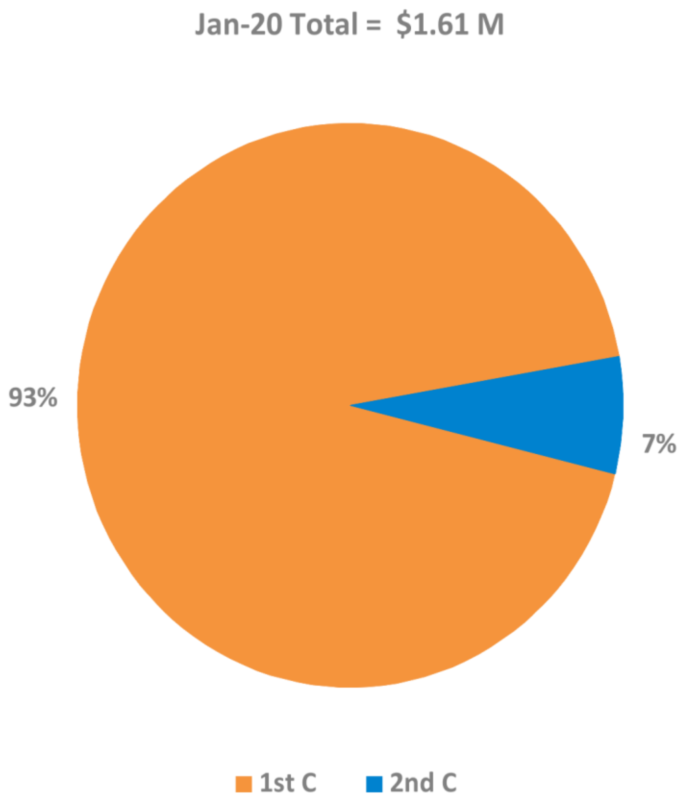


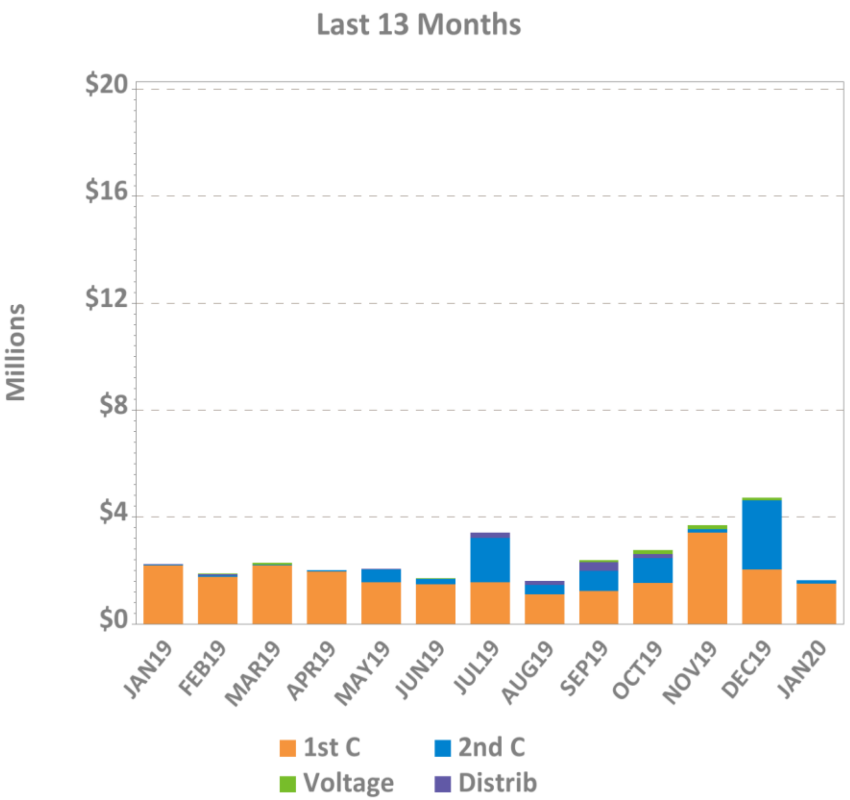
* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

DA and RT NCPC Charges



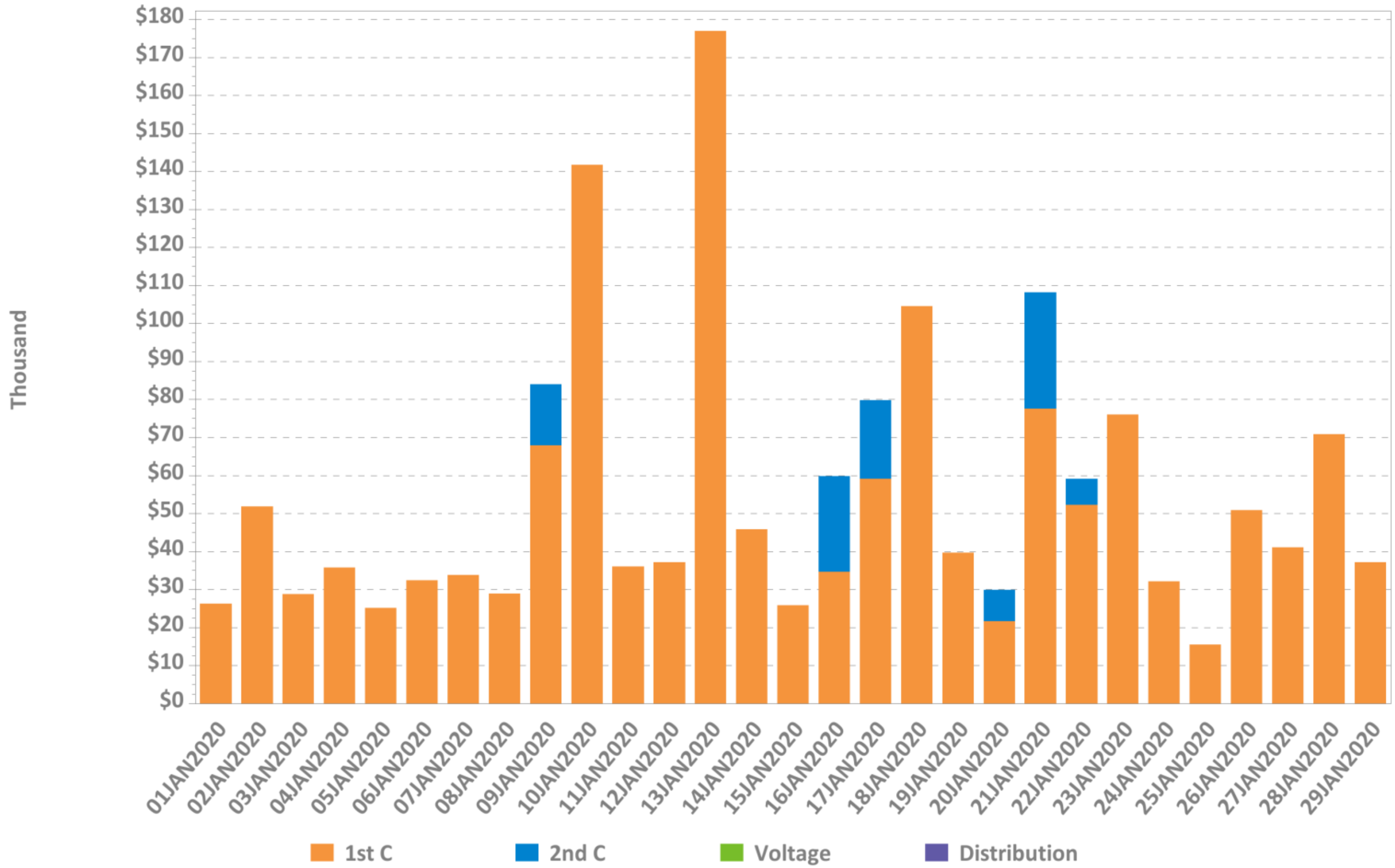
NCPC Charges by Type



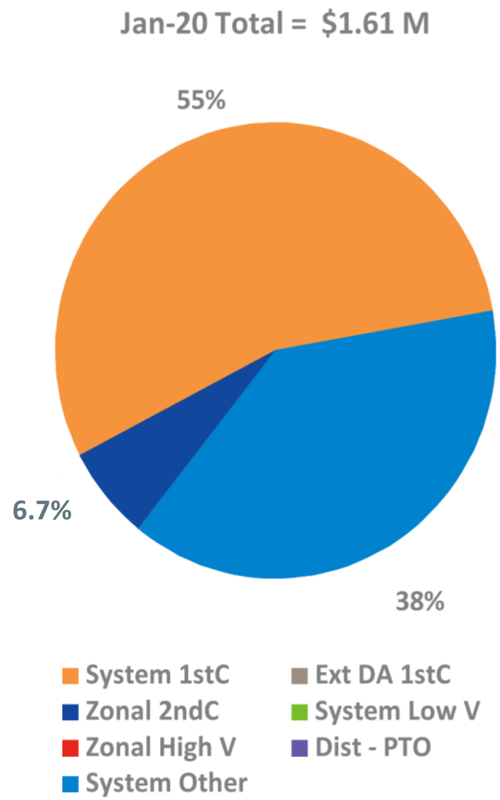


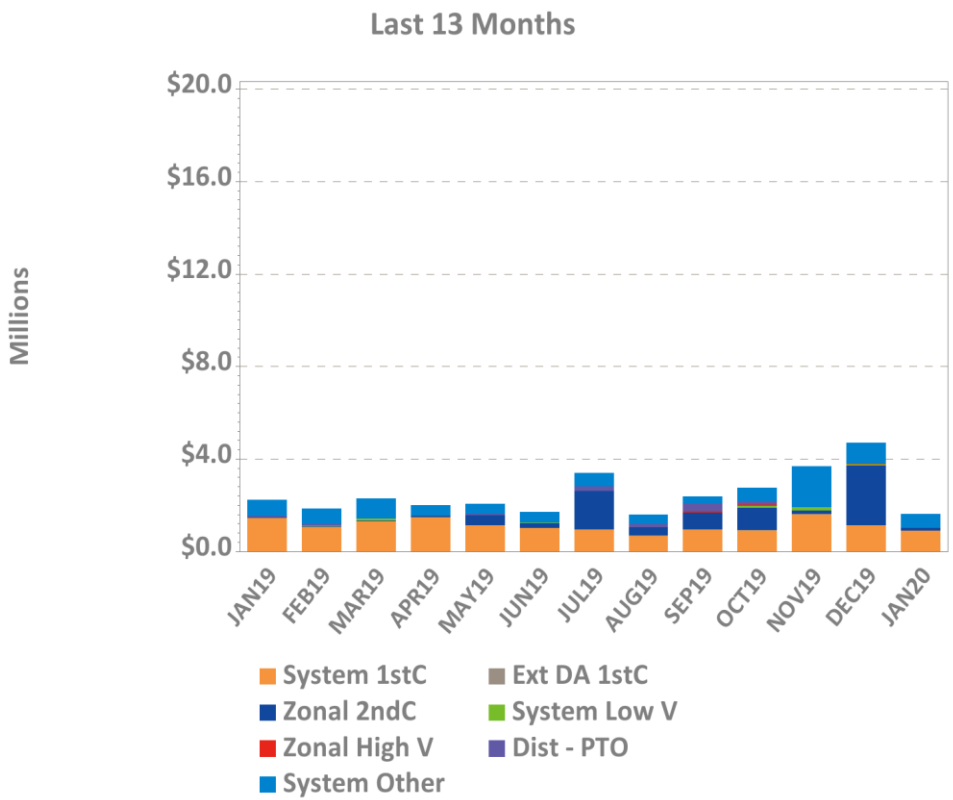
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



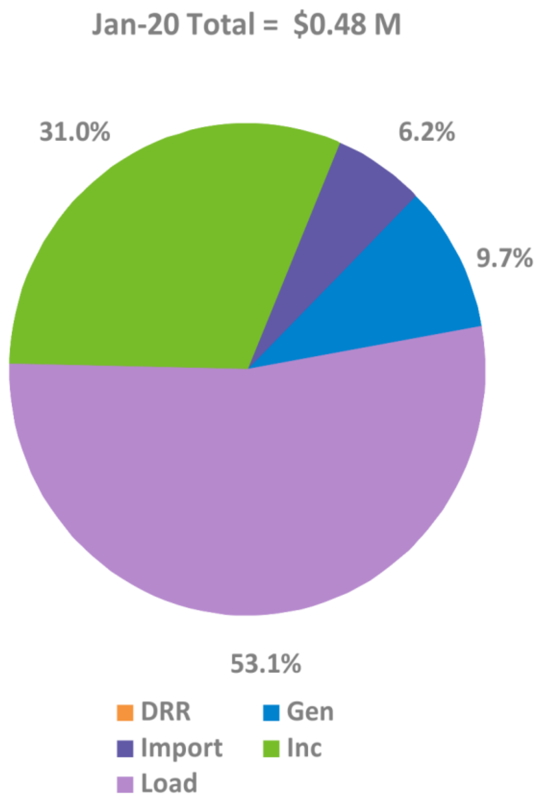
NCPC Charges by Allocation

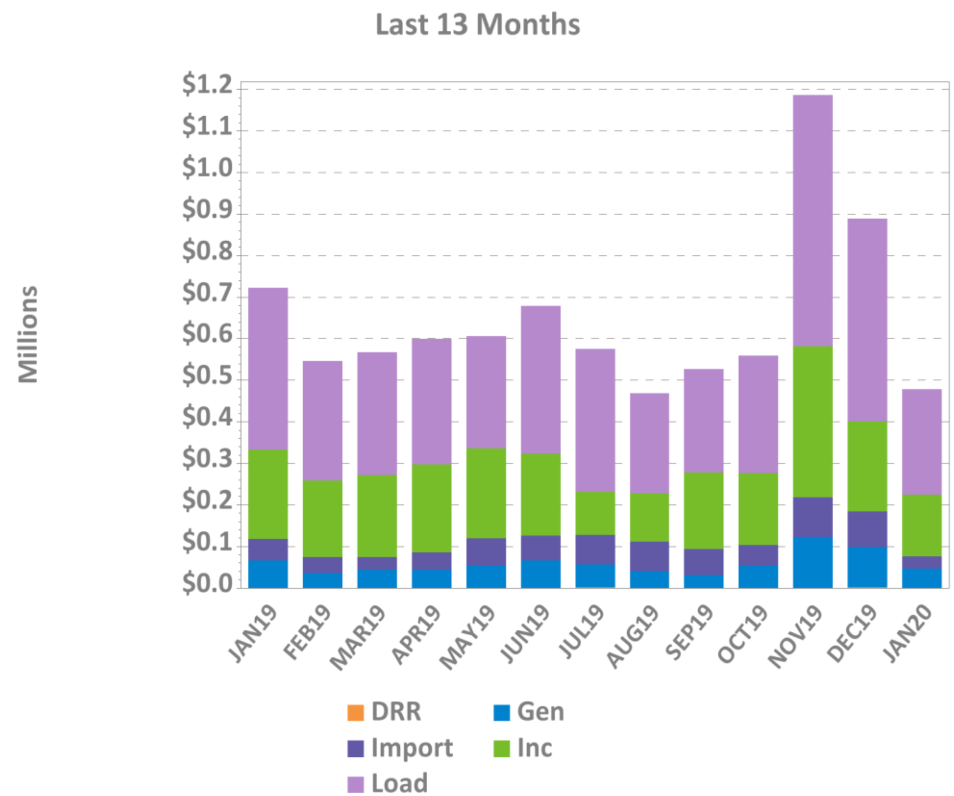




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

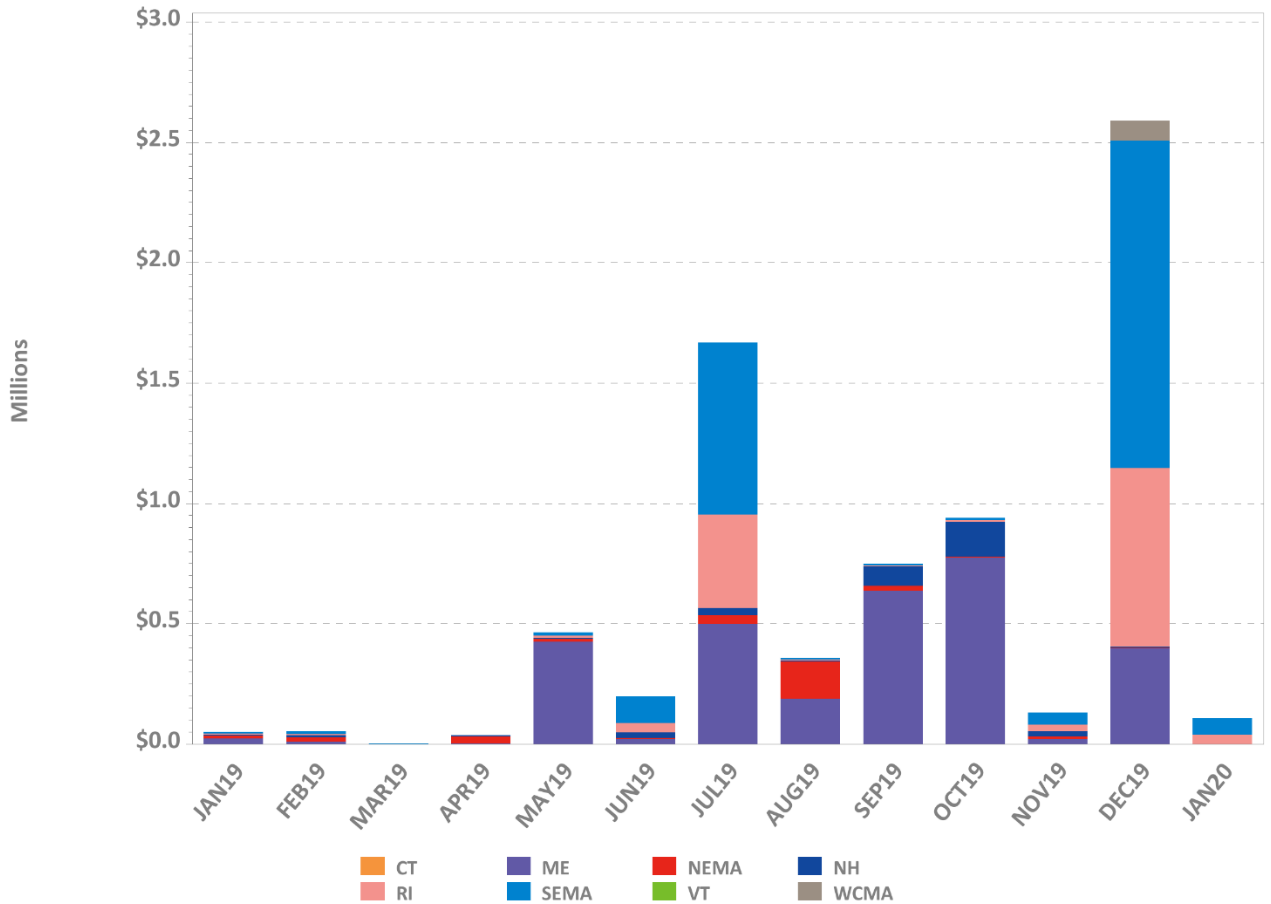
RT First Contingency Charges by Deviation Type





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

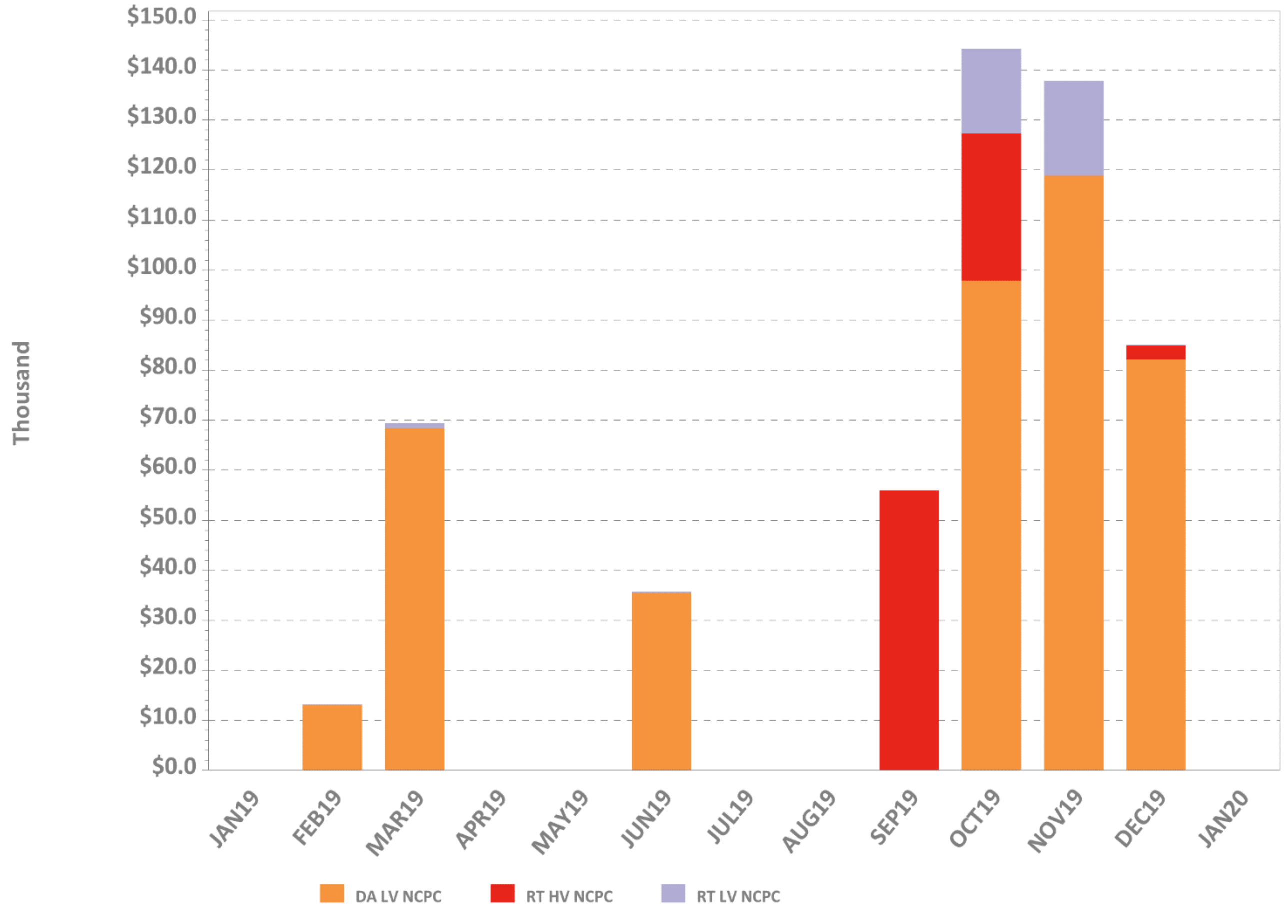
LSCPR Charges by Reliability Region



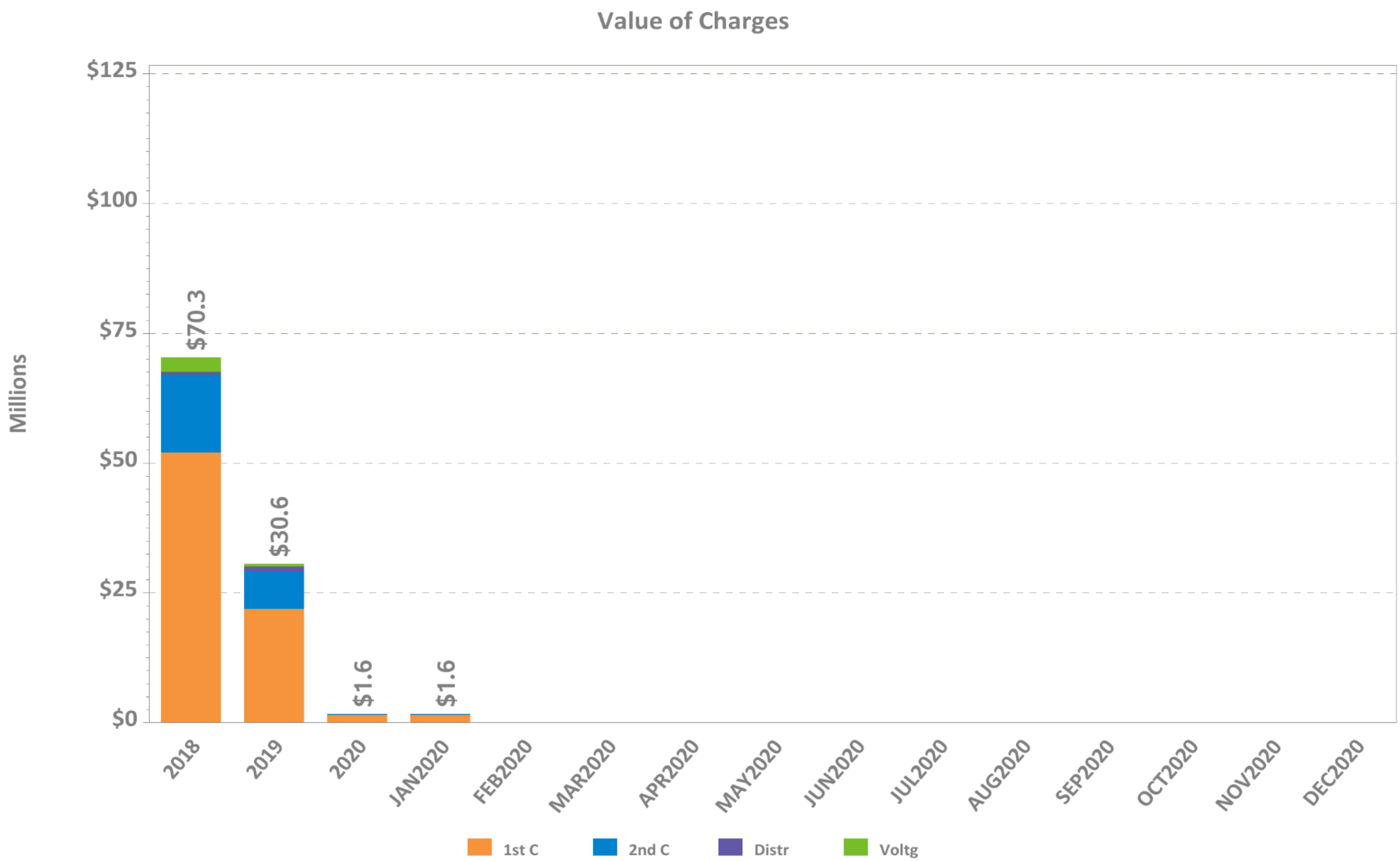
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

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

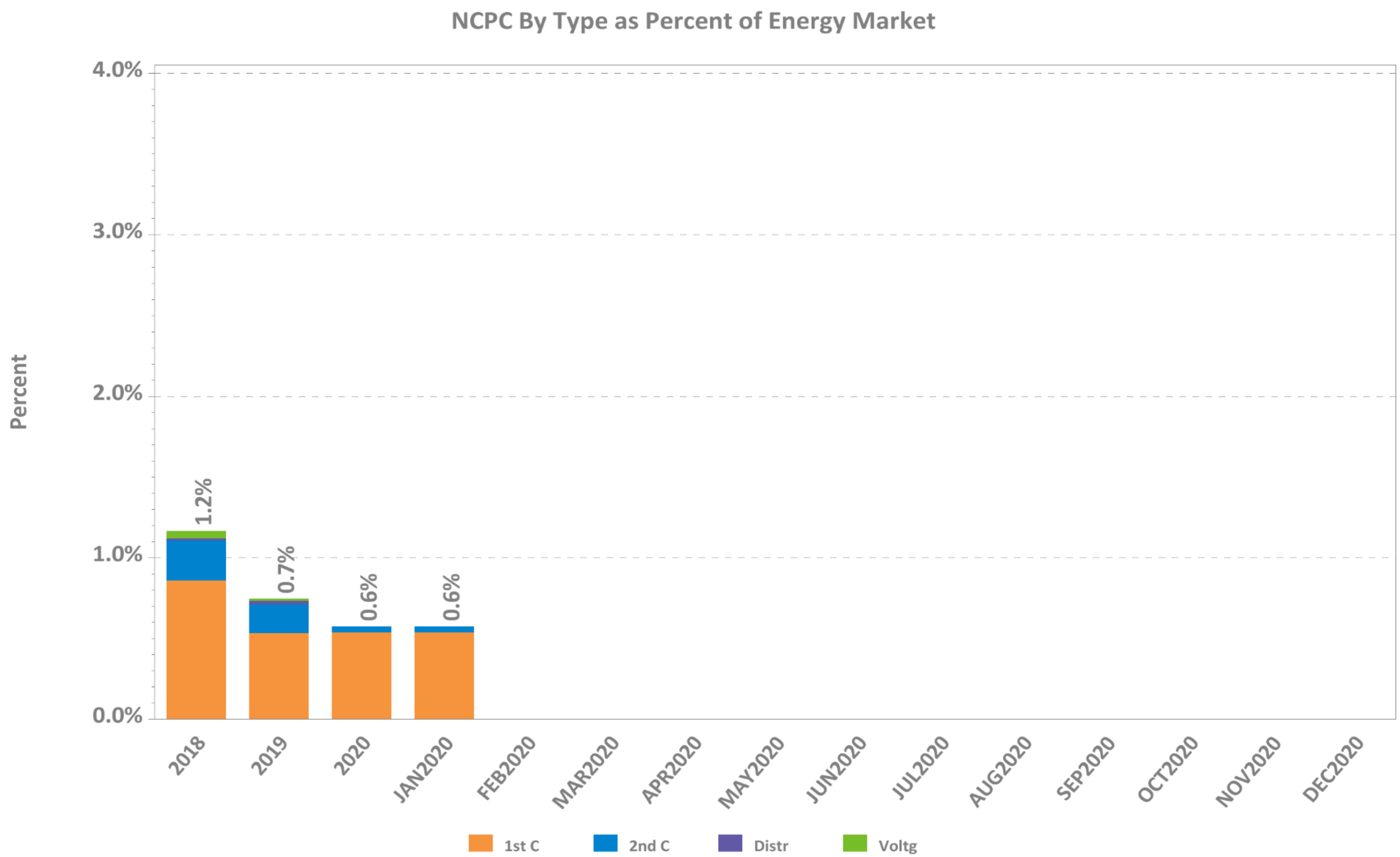
NCPC Charges for Voltage Support and High Voltage Control



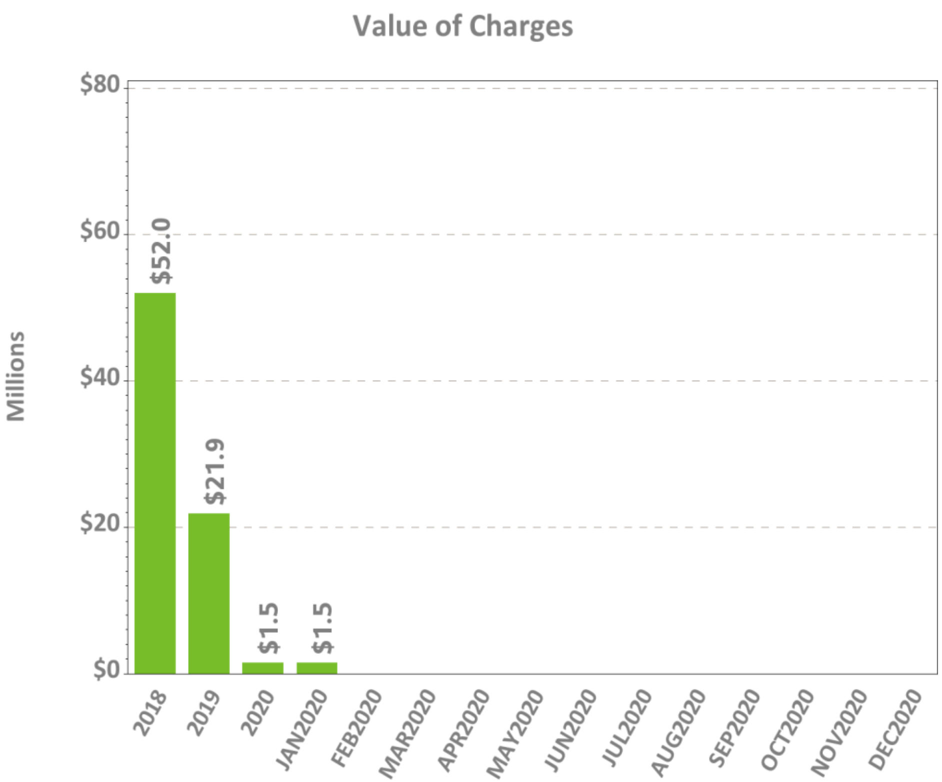
NCPC Charges by Type

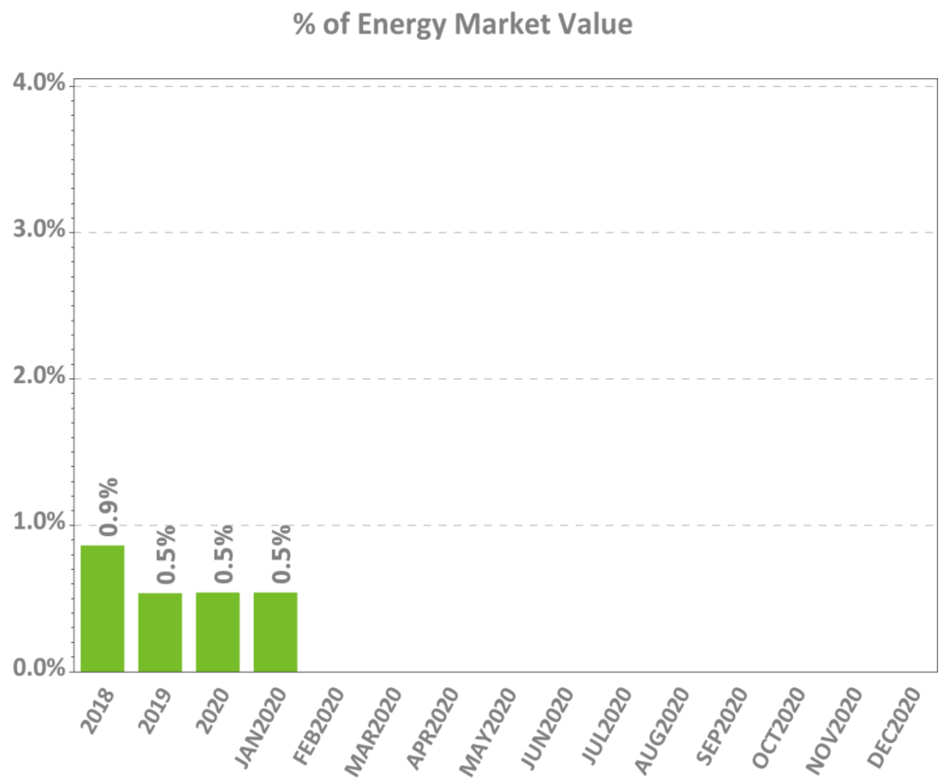


NCPC Charges as Percent of Energy Market



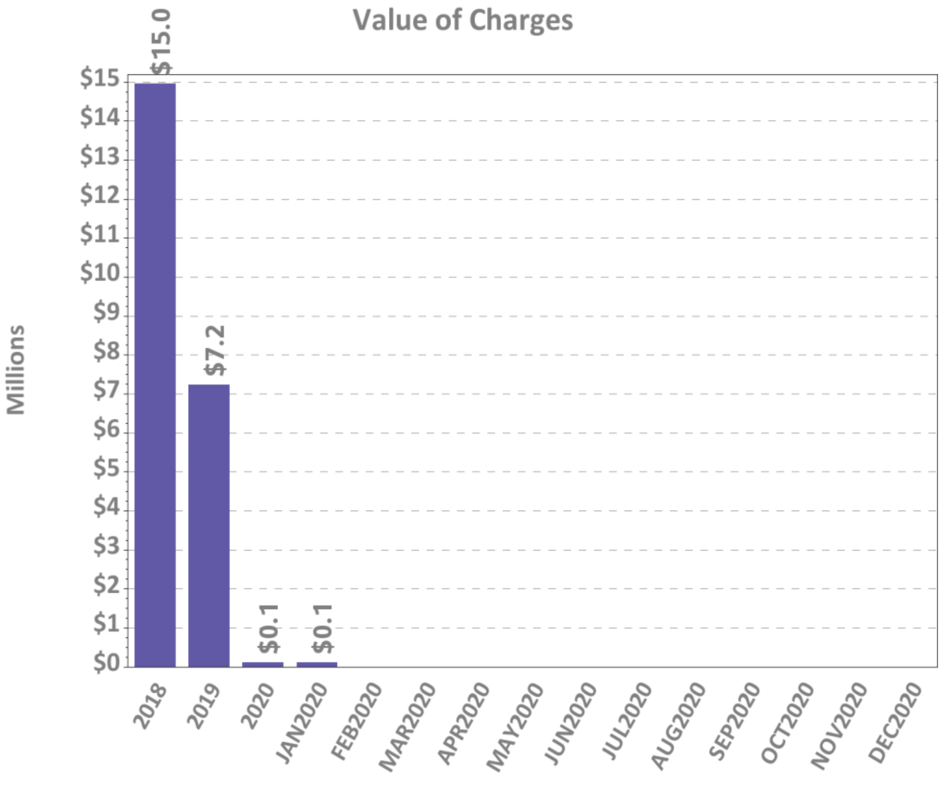
First Contingency NCPC Charges

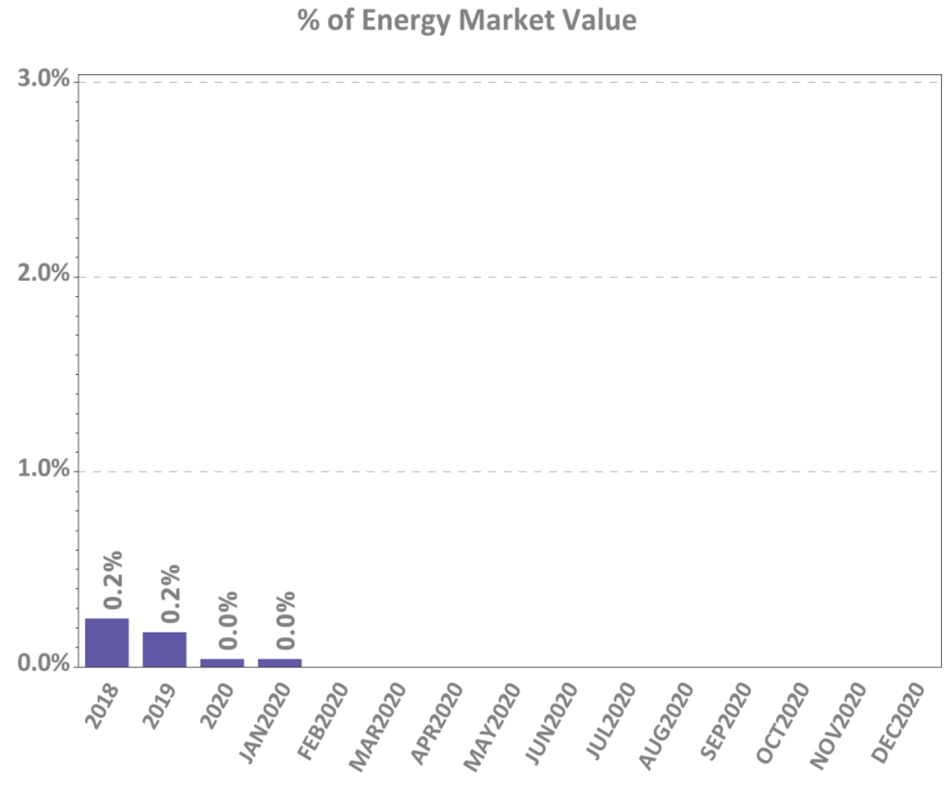




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

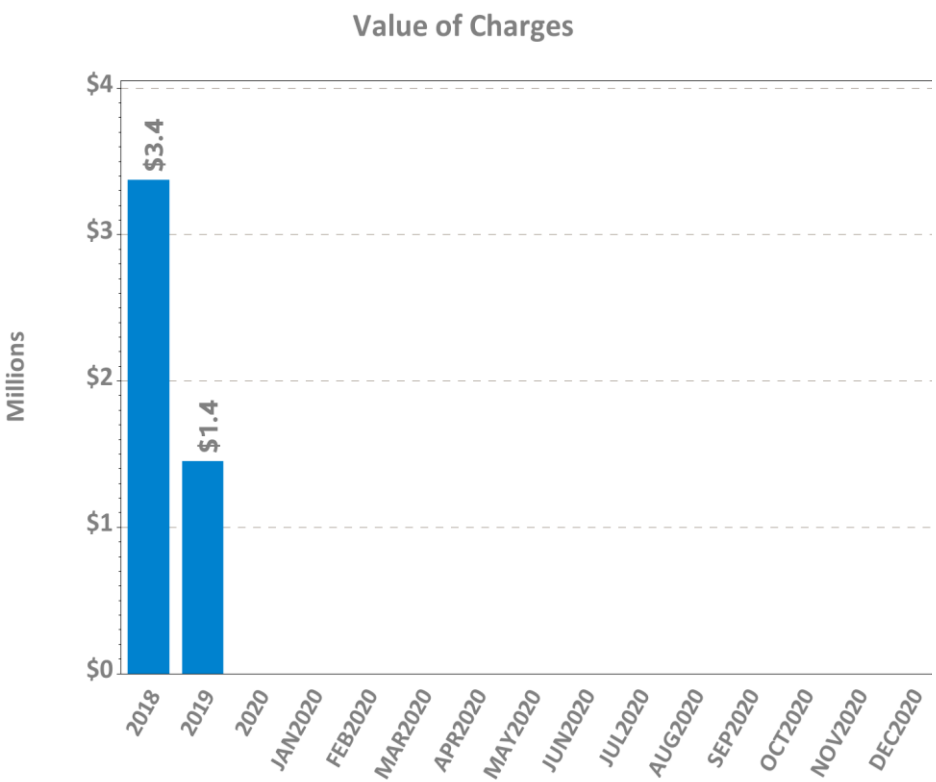
Second Contingency NCPC Charges

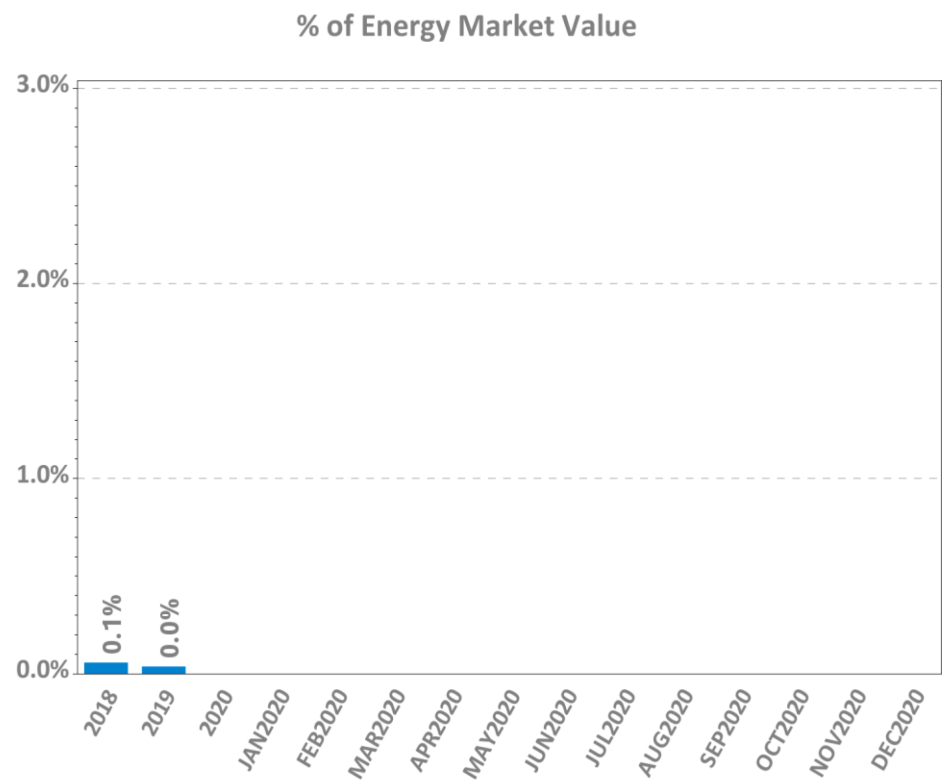




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

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

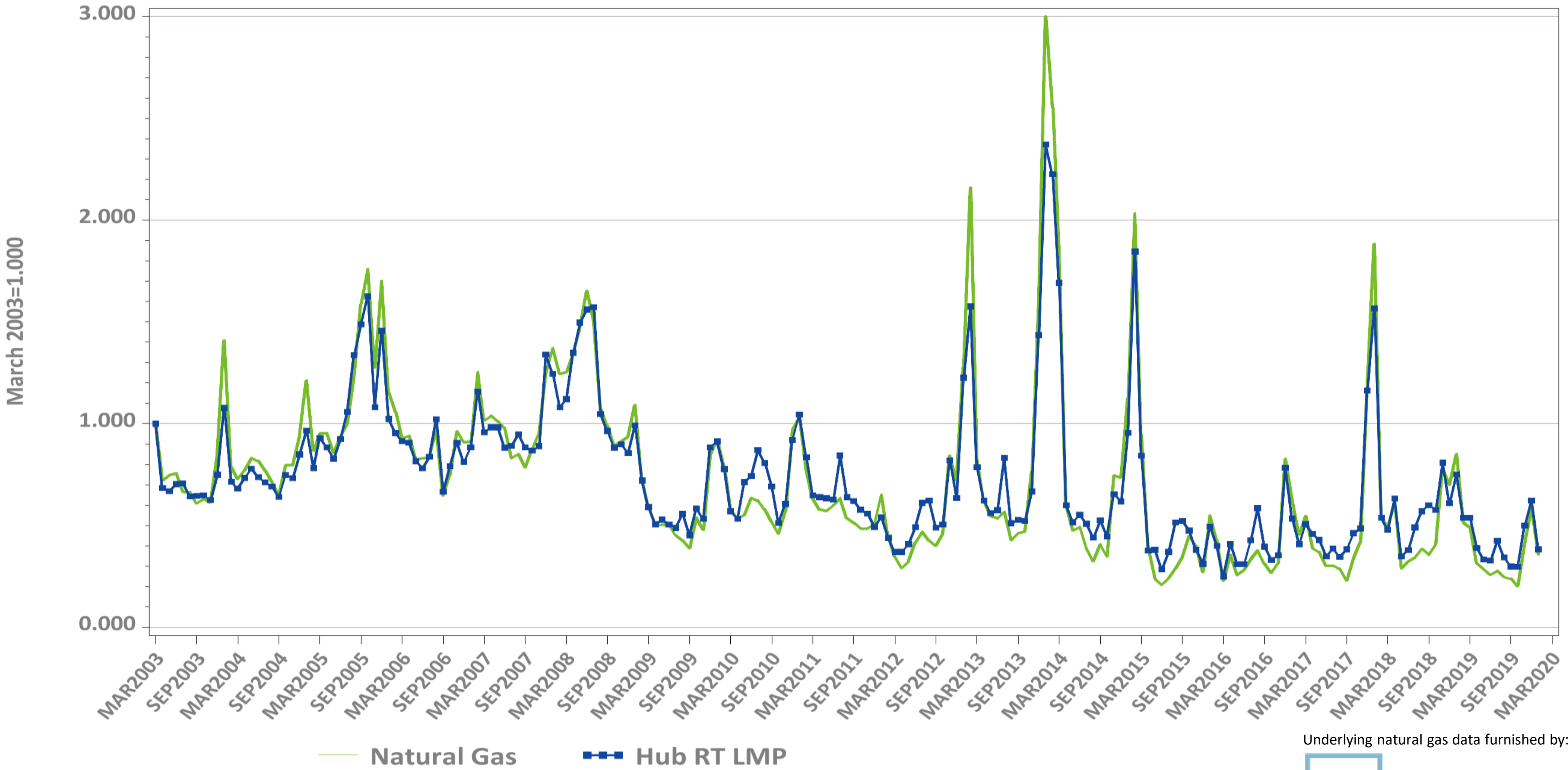
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 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%
Year 2019	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$31.54	$30.72	$30.76	$31.20	$30.67	$31.19	$31.51	$31.24	$31.22
Real-Time	$30.92	$30.26	$30.12	$30.70	$30.05	$30.61	$30.80	$30.68	$30.67
RT Delta %	-2.0%	-1.5%	-2.1%	-1.6%	-2.0%	-1.9%	-2.2%	-1.8%	-1.8%

January-19	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$57.07	$55.81	$55.53	$56.43	$55.79	$56.89	$56.97	$56.74	$56.76
Real-Time	$51.78	$50.68	$50.28	$51.22	$50.28	$51.59	$51.60	$51.42	$51.50
RT Delta %	-9.3%	-9.2%	-9.4%	-9.2%	-9.9%	-9.3%	-9.4%	-9.4%	-9.3%
January-20	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$26.88	$25.89	$26.56	$26.78	$26.03	$26.77	$27.04	$26.63	$26.66
Real-Time	$26.49	$25.69	$26.25	$26.39	$25.67	$26.39	$26.64	$26.24	$26.29
RT Delta %	-1.5%	-0.8%	-1.2%	-1.5%	-1.3%	-1.4%	-1.5%	-1.5%	-1.4%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	-52.9%	-53.6%	-52.2%	-52.5%	-53.3%	-52.9%	-52.5%	-53.1%	-53.0%
Yr over Yr RT	-48.9%	-49.3%	-47.8%	-48.5%	-48.9%	-48.9%	-48.4%	-49.0%	-49.0%

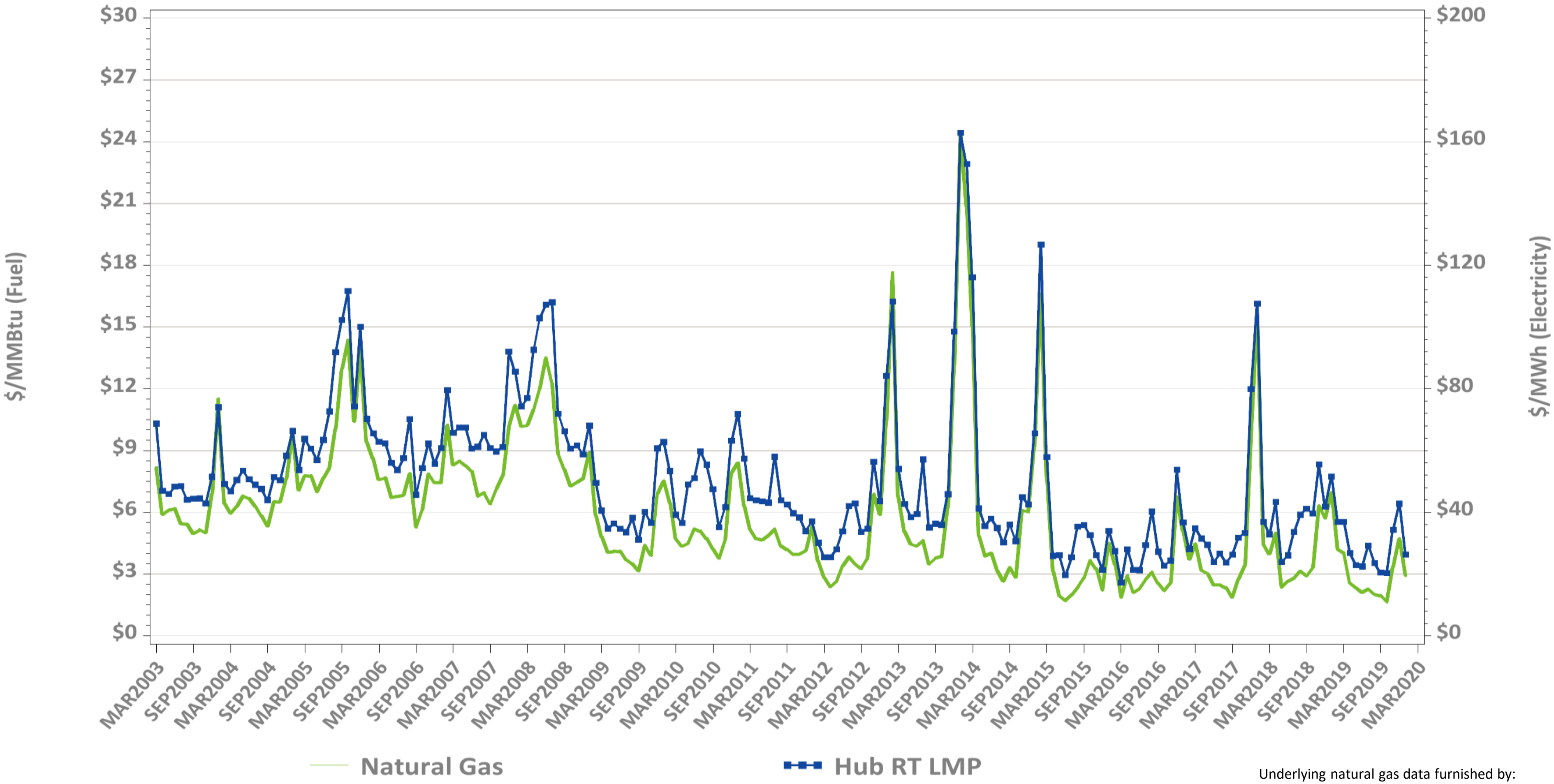
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

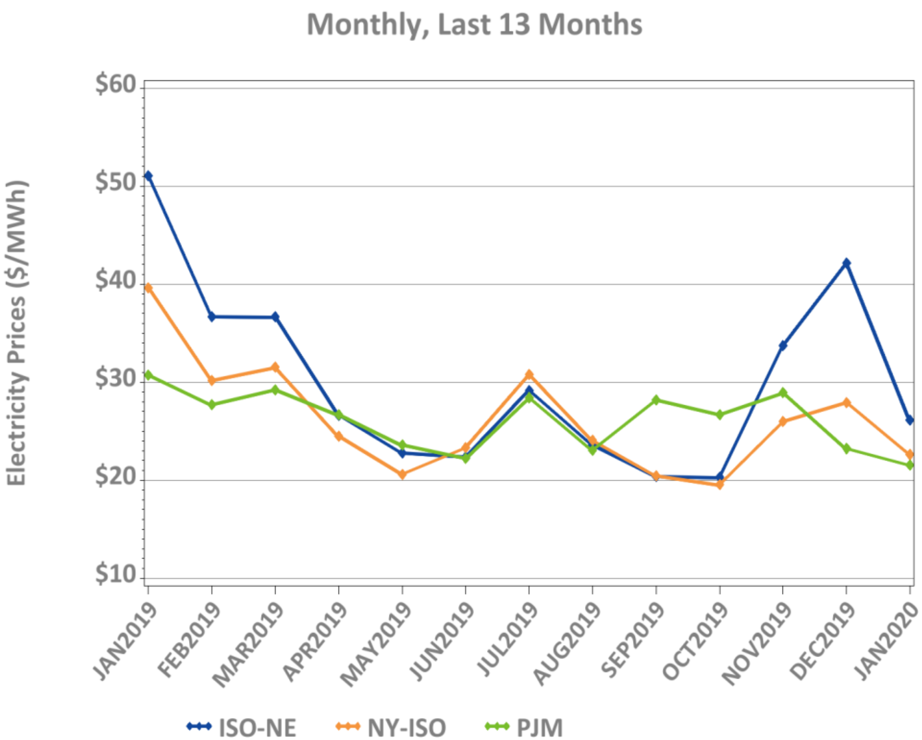
ICE Global markets in clear view

Monthly Average Fuel Price and RT Hub LMP

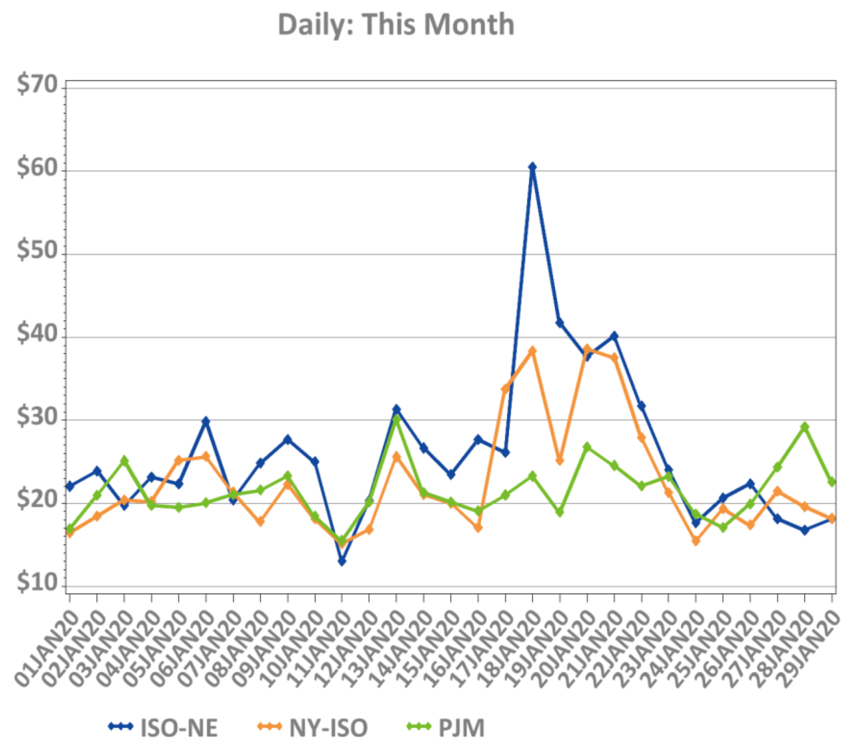


Underlying natural gas data furnished by: ice Global markets in clear view

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

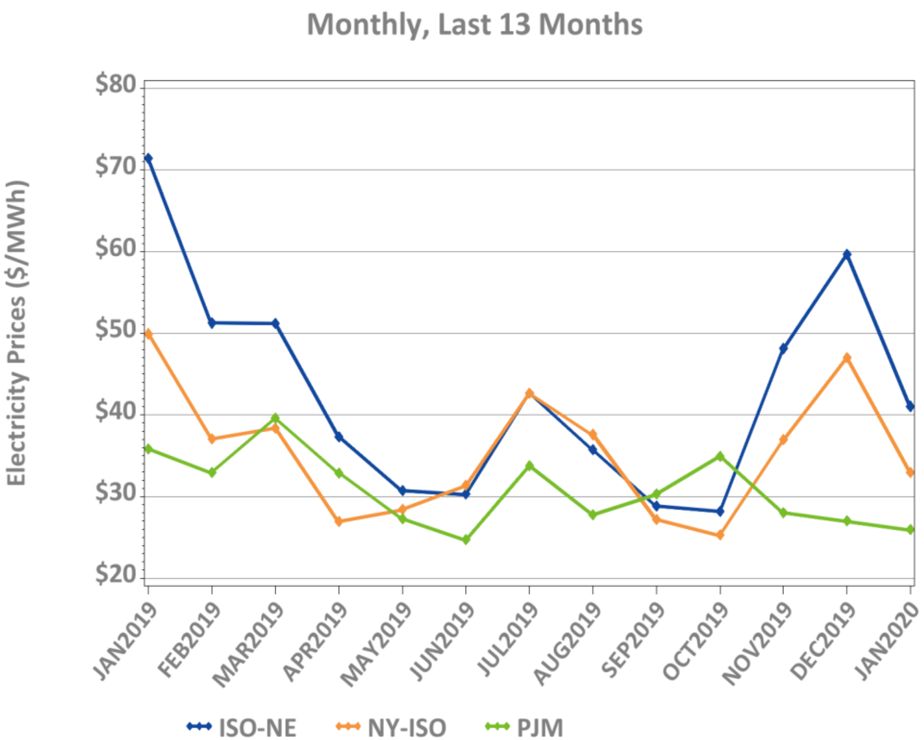


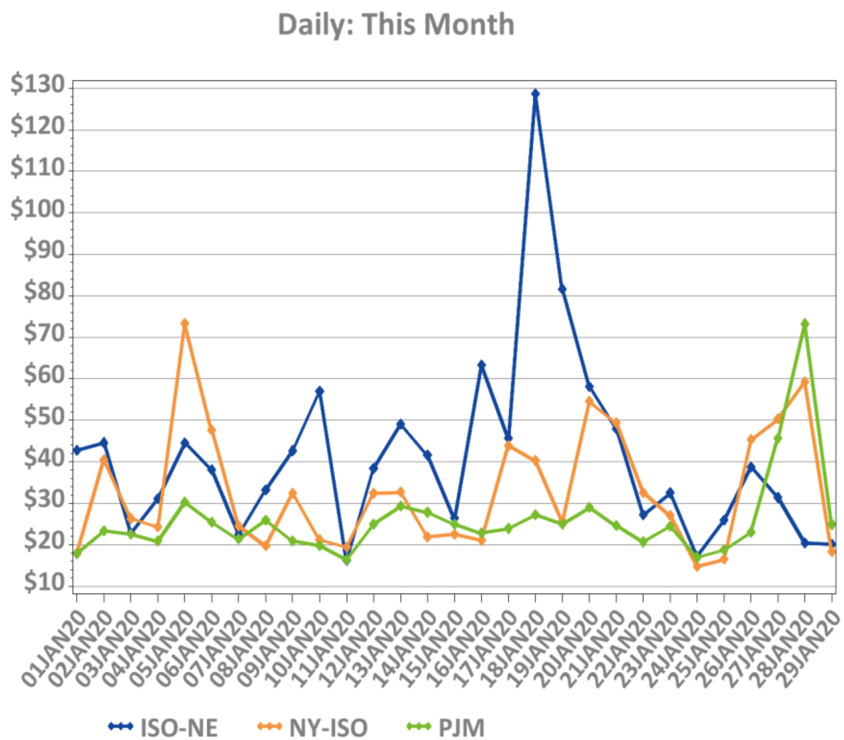
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

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





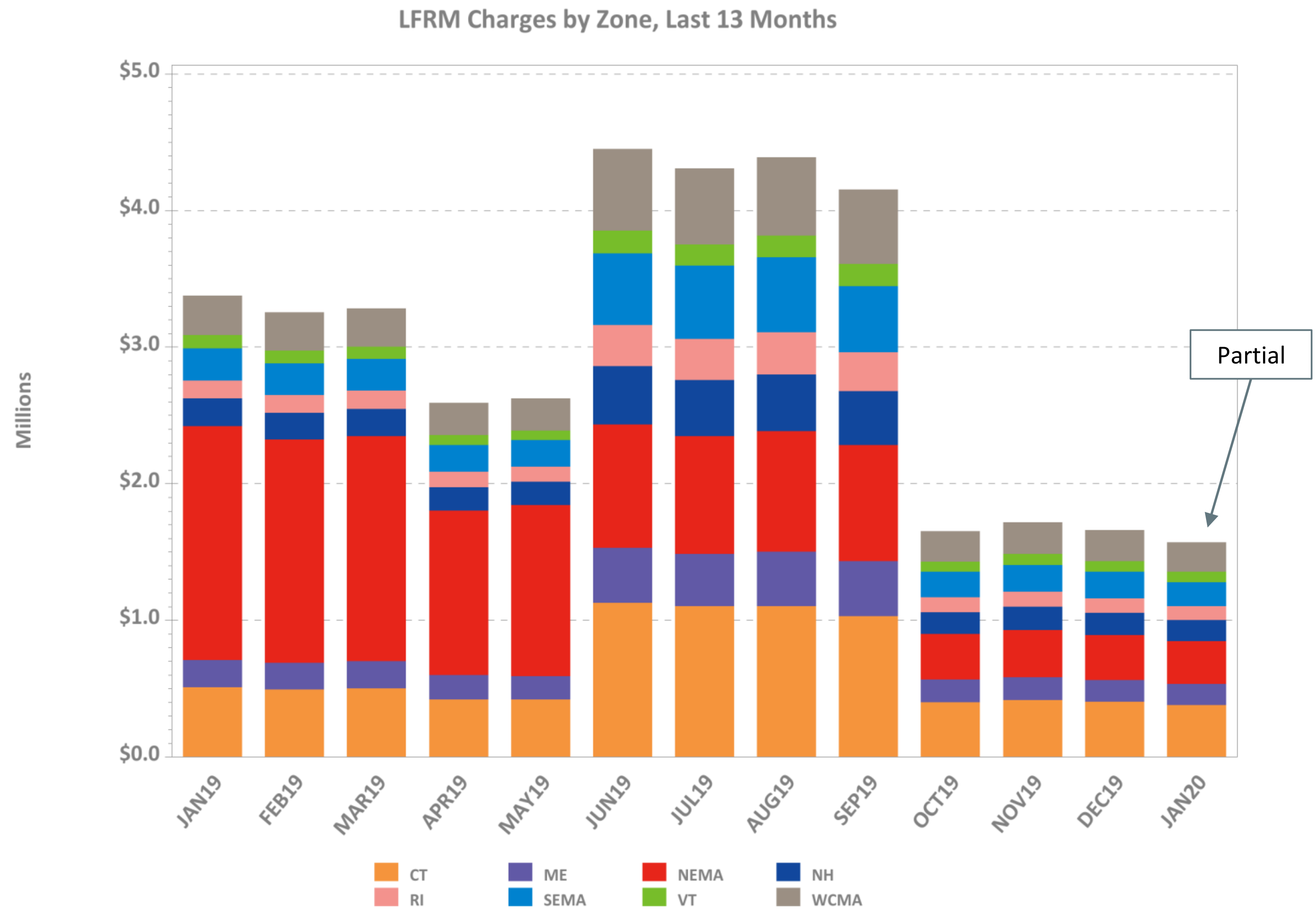
***Forecasted New England daily peak hours reflected**

Reserve Market Results – January 2020

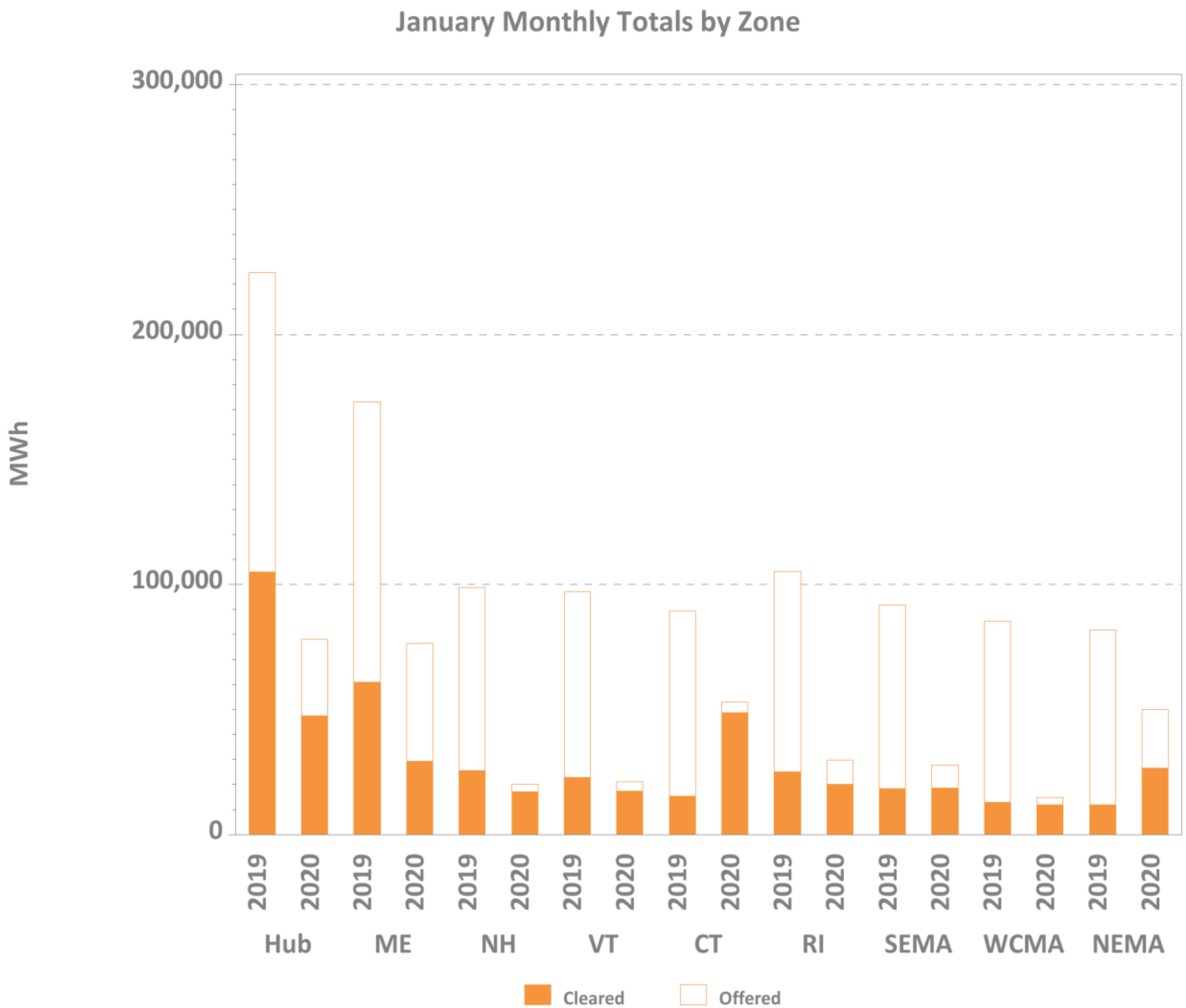
- Maximum potential Forward Reserve Market payments of \$1.6M were reduced by credit reductions of \$8K, failure-to-reserve penalties of \$12K and no failure-to-activate penalties, resulting in a net payout of \$1.6M or 99% of maximum
  - Rest of System: \$1.2M/1.21M (99%)
  - Southwest Connecticut: \$0.04M/0.05M (87%)
  - Connecticut: \$0.32M/0.33M (98%)
- \$407K total Real-Time credits were not reduced by any Forward Reserve Energy Obligation Charges for a net of \$409K in Real-Time Reserve payments
  - Rest of System: 232 hours, \$236K
  - Southwest Connecticut: 232 hours, \$72K
  - Connecticut: 232 hours, \$48K
  - NEMA: 232 hours, \$54K

Note: "Failure to reserve" results in both credit reductions and penalties in the Locational Forward Reserve Market. While this summary reports performance by location, there were no locational requirements in effect for the current Forward Reserve auction period.

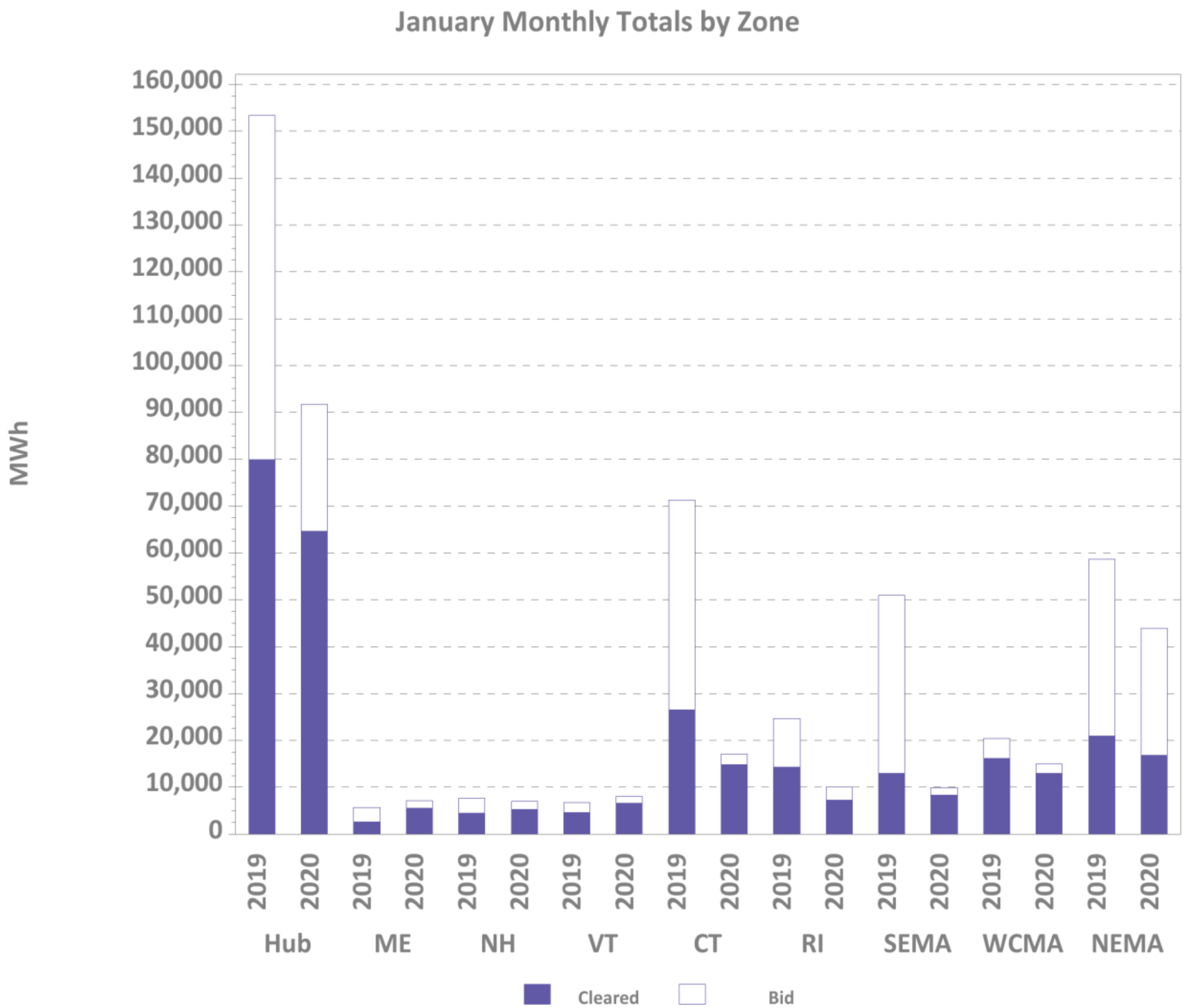
LFRM Charges to Load by Load Zone ($)



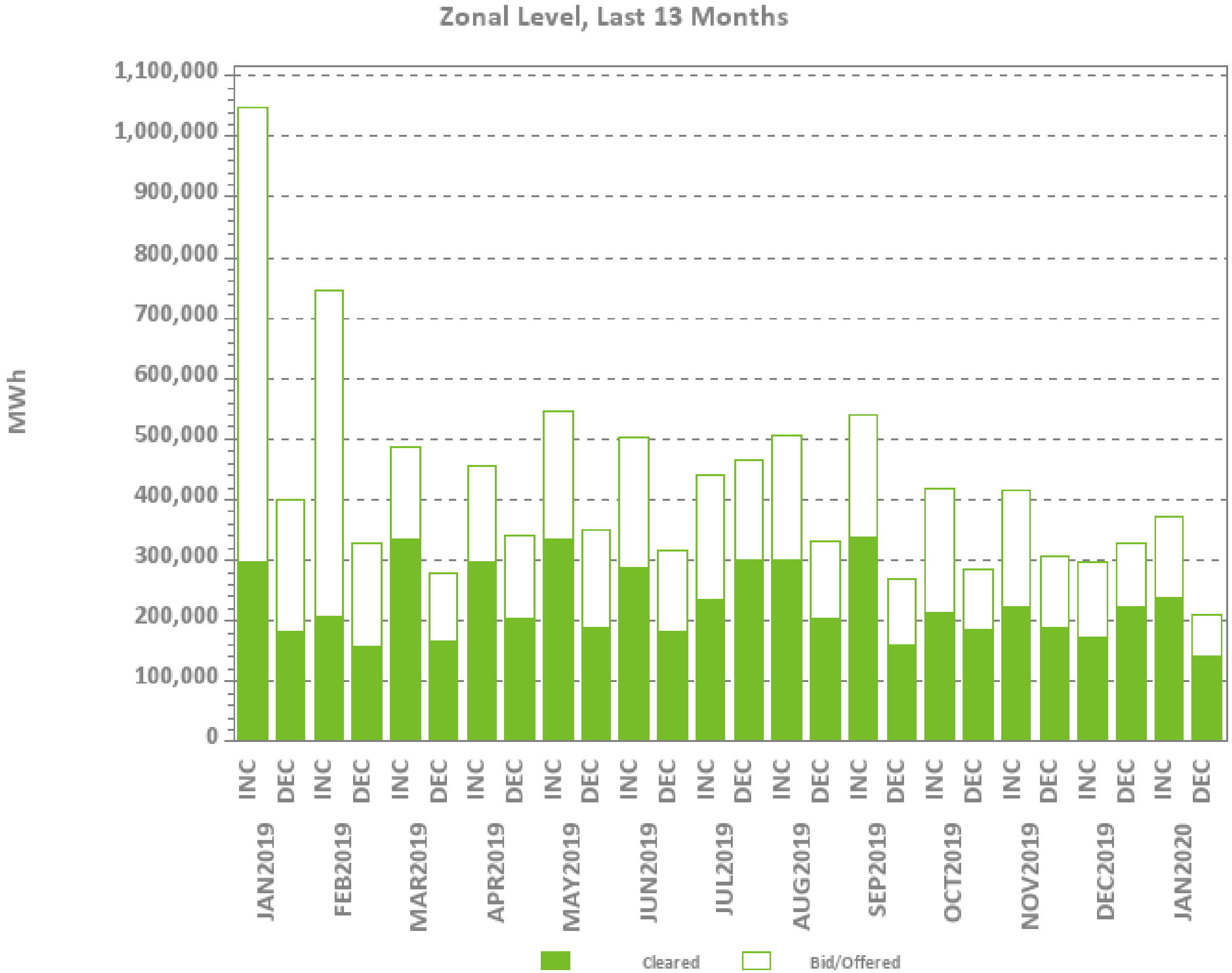
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

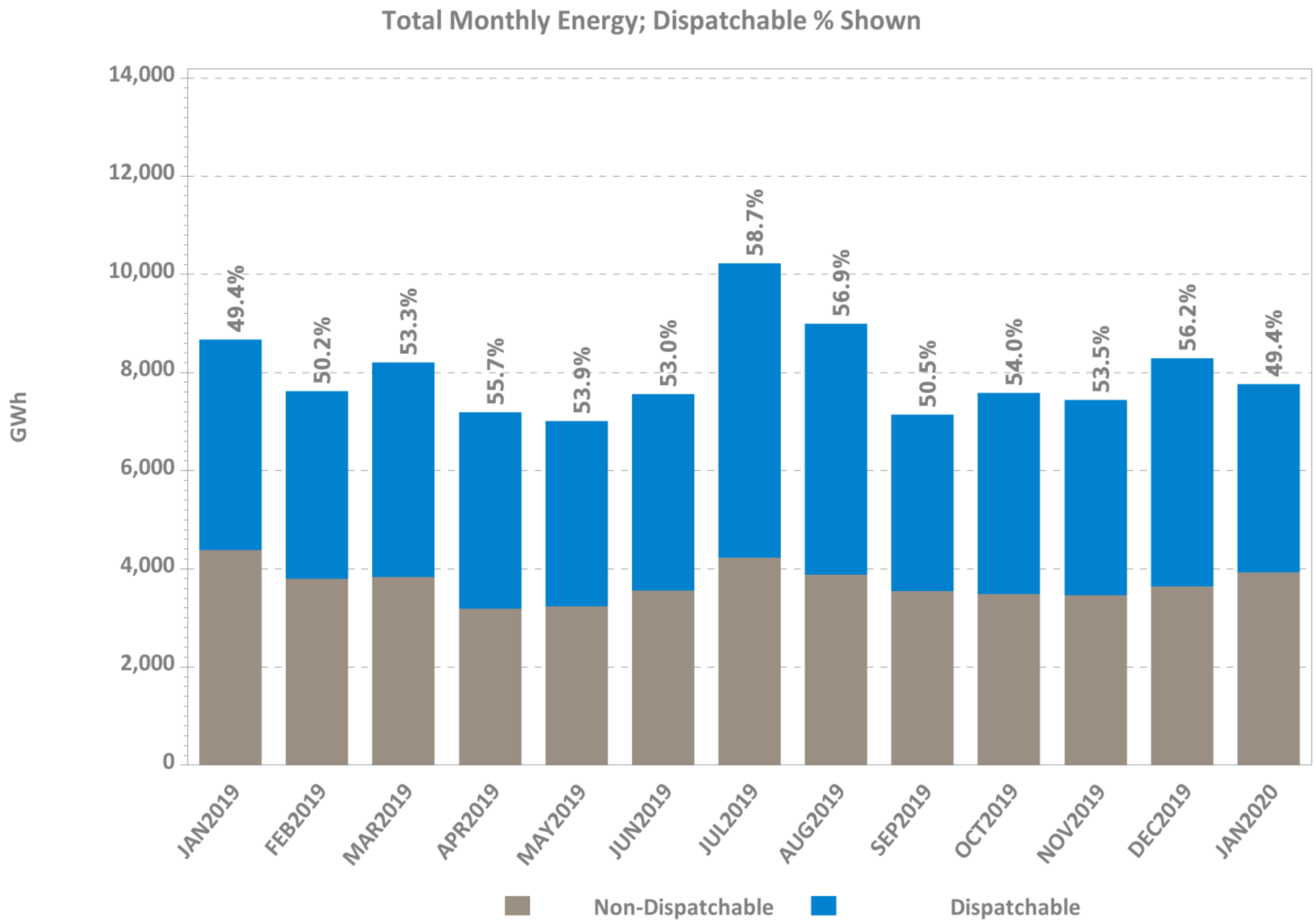


Total Increment Offers and Decrement Bids



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.

REGIONAL SYSTEM PLAN (RSP)

Future Regional System Plans

- Prior to developing the next Regional System Plan (RSP), the ISO would like input from stakeholders on how to enhance the report
- On January 23, the ISO sent a short survey to New England stakeholders (PAC members as well as NEPOOL committees such as the TC and PC)
  - Survey responses are due February 13
- Goals
  - Increase usability of the RSP
  - Focus on content that stakeholders are interested in
  - Find new ways to keep the RSP forward looking
  - Streamline the development process
  - Increase visibility of the regional system planning process

Planning Advisory Committee (PAC)

- February 20 PAC Meeting Agenda Topics*
  - Stakeholder Presentations of Public Policy Requirements for New England Transmission Needs
  - 2019 NESCOE Economic Study Results (8,000 MW Scenario)
  - NEMA/Boston Import Transfer Capability - Update for FCA 15
  - ISO Wind Data Study
  - Upper ME 2029 Needs Assessment Results
  - Western and Central Massachusetts (WCMA) 2029 Needs Assessment Results
  - Glenbrook STATCOM Rebuild Project - Eversource
  - Update on Implementation Plan for Revised NPCC Directory 1 - National Grid

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

Economic Studies

- Economic study requests were submitted by Anbaric, NESCOE, and RENEW Northeast
  - Detailed assumptions for each study request were discussed at the August 8 PAC meeting
- Preliminary results for the NESCOE study (up to 6,000 MW of offshore wind additions) were presented at the December 19 PAC meeting
  - Answers to questions raised on the preliminary results were discussed at the January 23 PAC meeting
  - Additional results to be presented in February related to the 8,000 MW scenario
  - The transmission portion of the study anticipated to be completed in the March-April timeframe
- Preliminary results for the Anbaric and RENEW studies are anticipated to be discussed with PAC in the March-May timeframe
- The ISO plans to complete reports for all three requests by Q2 2020

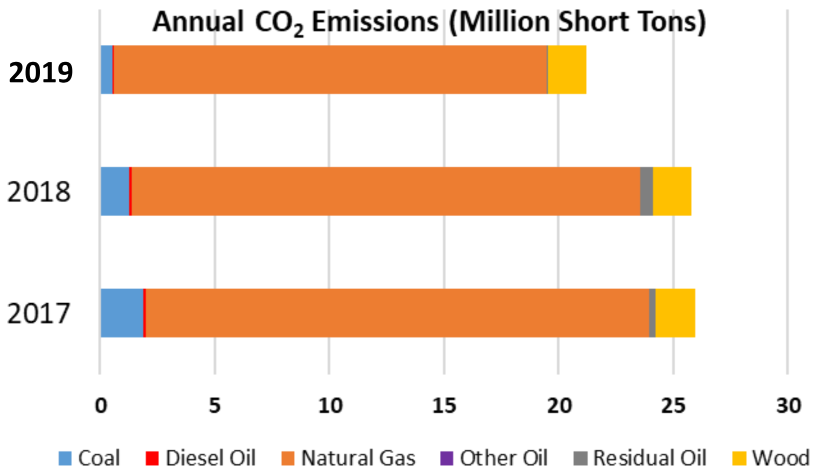
2018 Generator Emissions Report

- Preparation of the Annual Electric Generator Air Emissions Report is underway and expected to be completed in the April timeframe
- Preliminary results for the load-weighted and non-load-weighted marginal resource analyses will be presented to the EAG on February 18
  - Similar methodology that ISO-NE's market monitoring unit uses
- Efforts to include emission intensity of imports into New England are being considered as well as the ability to report emissions information more frequently

Environmental Matters – Annual Emissions

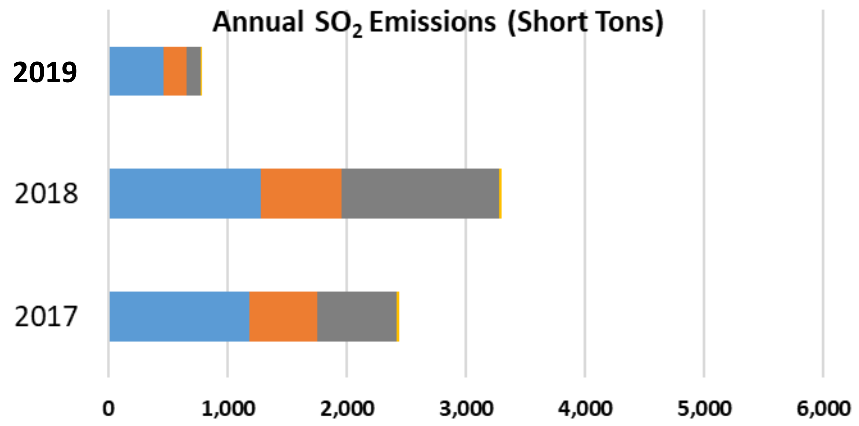
Reported to EPA by native emitting generators directly

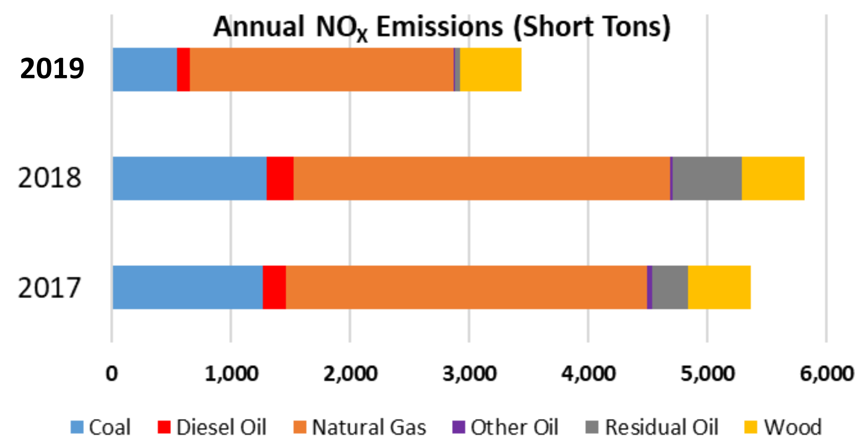
Regional 2019 CO_2 Emissions Trend Lower for All Fuel Types



- Compared to 2017 & 2018, a 4% decline in NEL during 2019 vs. 2018 caused all emissions to decline:
  - CO_2 emissions < 18%
  - SO_2 emissions < 73%
  - NO_x emissions < 39%

Lower Production by All Fuel Types Lowers Other System Emissions





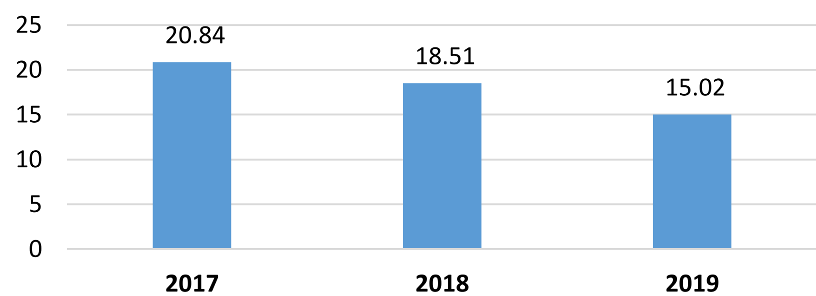
Environmental Matters – Massachusetts CO_2 Generator Emissions Cap

2019 Emissions Declined 23%, Generation Declined 19% vs. 2018

2019 CO_2 Emissions Well Below Cap

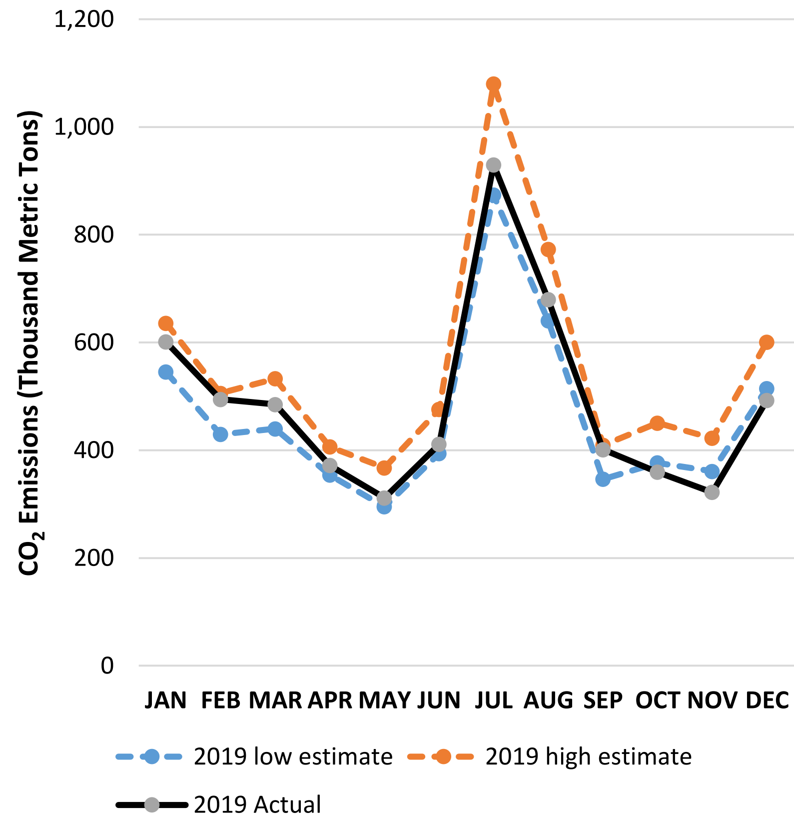
- 2019: **8.73** million metric ton (MMT) cap (25% auctioned, 75% allocated)
  - 2019 actual emissions **5.86** MMT
- 2020: **8.50** MMT cap (50% auctioned, 50% allocated)
- Generation from GWSA affected generators declined 19%, while NEL overall declined 4%

GWSA Annual Generation (TWh)



GWSA - Global Warming Solutions Act

2019 Estimated v. Actual GWSA CO_2 Cap Emissions



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 1/27/20

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 1/27/20

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 1/27/20

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 1/27/20

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 1/27/20

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	Jun-20	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)	Jun-20	3

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 1/27/20

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)	Jun-20	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 1/27/20

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 1/27/20

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 1/27/20

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

Upgrade	Expected/ Actual In-Service	Present Stage
Add two 14.4 MVAR capacitor banks at the West Brookfield substation	Dec-17	4
Add a new 115 kV line from Plumtree to Brookfield Junction	Jun-18	4
Reconductor the 115 kV line between West Brookfield and Brookfield Junction (1887)	Dec-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 1/27/20

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	4
Reconductor the 115 kV line from Ridgefield Junction to Peaceable (1470-3)	Dec-19	4

Southwest Connecticut Projects, cont.

Status as of 1/27/20

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)	Jun-21	2

Southwest Connecticut Projects, cont.

Status as of 1/27/20

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 1/27/20

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	3*
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 1/27/20

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	May-20	3
Install third 115 kV line from West Walpole to Holbrook	May-20	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-23	2

Greater Boston Projects, cont.

Status as of 1/27/20

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	4
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	Jul-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-20	3

Greater Boston Projects, cont.

Status as of 1/27/20

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-21	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 1/27/20

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	Dec-19	4
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 1/27/20

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 1/27/20

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 1/27/20

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	3

SEMA/RI Reliability Projects

Status as of 1/27/20

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	May-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	3
1716	Increase clearances on E-183E & F-184 lines between Brayton Point and Grand Army substations	Nov-19	4
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	4

SEMA/RI Reliability Projects, cont.

Status as of 1/27/20

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	Dec-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 1/27/20

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 1/27/20

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

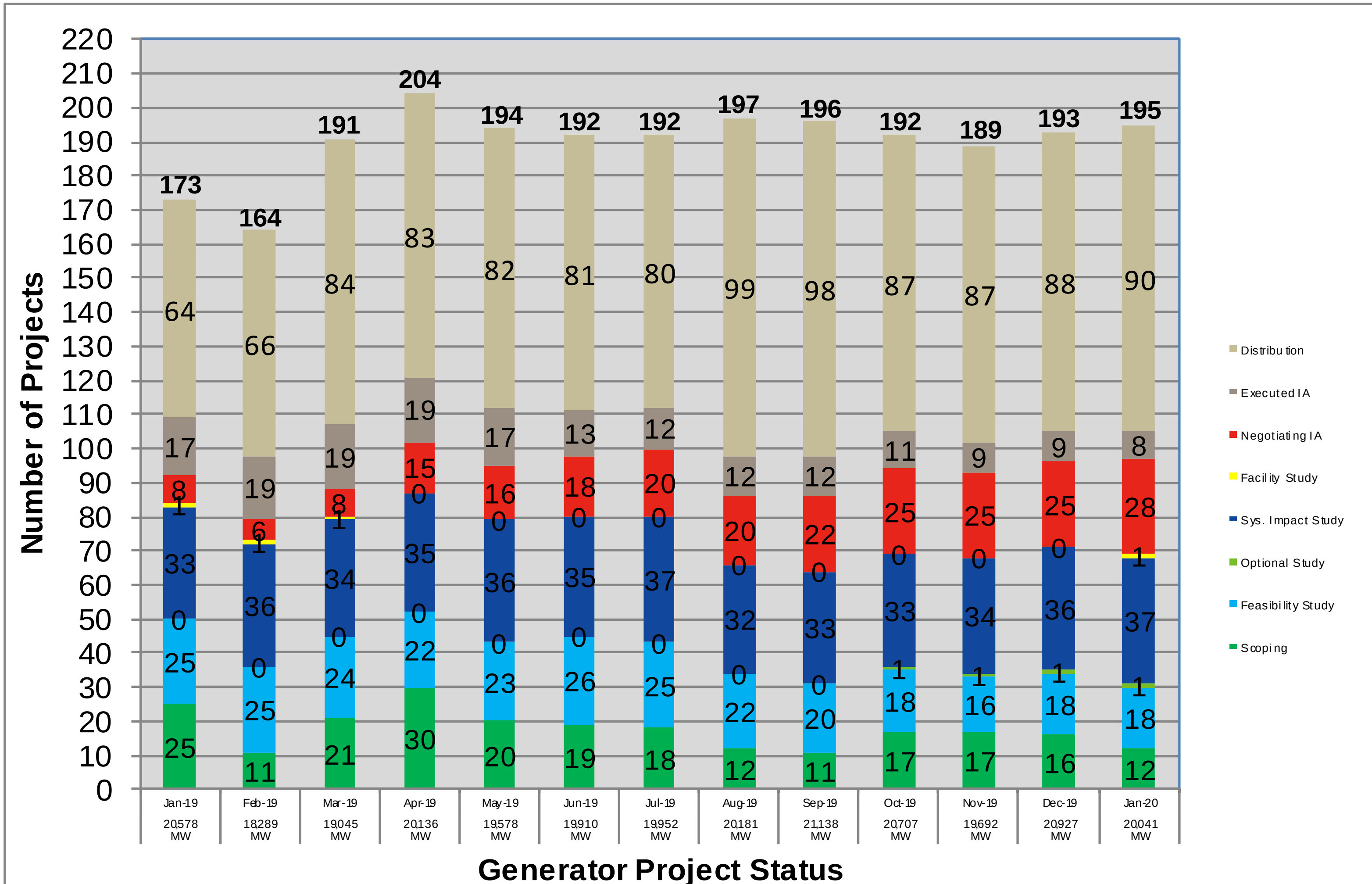
SEMA/RI Reliability Projects, cont.

Status as of 1/27/20

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	Feb-21	2
1789	West Medway 345 kV circuit breaker upgrades	Dec-21	2
1790	Medway 115 kV circuit breaker replacements	Dec-21	3

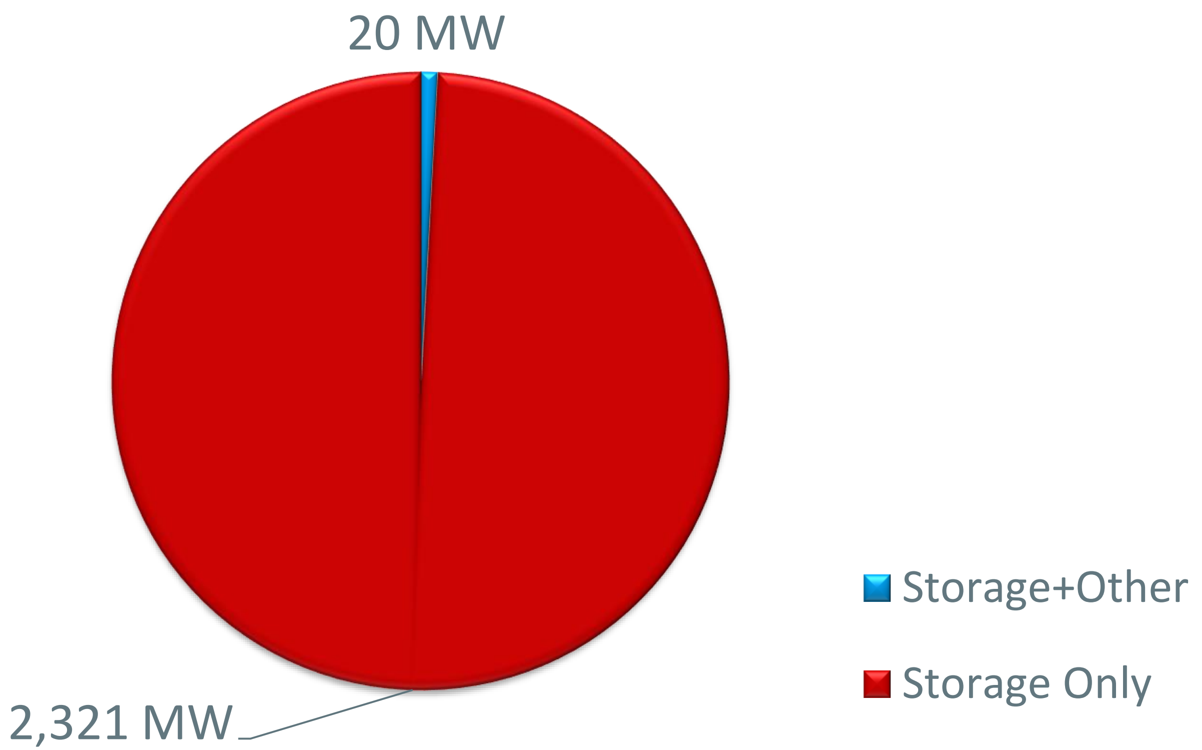
Status of Tariff Studies



As of January 2020, there are 4 ETU's in Scoping, 4 in FS, 4 in SIS, 0 in FAC, 1 Negotiating IA, and 1 with Executed IA
https://irtt.iso-ne.com/external.aspx

What is in the Queue (as of January 30, 2020)

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



OPERABLE CAPACITY ANALYSIS

Winter 2019/2020 Analysis

Winter 2019/2020 Operable Capacity Analysis

50/50 Load Forecast (Reference)	February - 2020[2] CSO (MW)	February - 2020[2] SCC (MW)
Operable Capacity MW [1]	31,029	33,821
Active Demand Capacity Resource (+) [5]	412	363
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,094	1,094
Non Commercial Capacity (+)	28	28
Non Gas-fired Planned Outage MW (-)	434	473
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	3,100	3,100
Generation at Risk Due to Gas Supply (-) [3]	2,958	3,269
Net Capacity (NET OPCAP SUPPLY MW)	26,071	28,464
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	19,967	19,967
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,272	22,272
Operable Capacity Margin	3,799	6,192

[1]Operable Capacity is based on data as of **January 20, 2020** 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 **January 20, 2020.**

[2] Load forecast that is based on the 2019 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **February 1, 2020.**

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

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

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

Winter 2019/2020 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	February - 2020[2] CSO (MW)	February - 2020[2] SCC (MW)
Operable Capacity MW [1]	31,029	33,821
Active Demand Capacity Resource (+) [5]	412	363
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,094	1,094
Non Commercial Capacity (+)	28	28
Non Gas-fired Planned Outage MW (-)	434	473
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	3,100	3,100
Generation at Risk Due to Gas Supply (-) [3]	4,204	4,645
Net Capacity (NET OPCAP SUPPLY MW)	24,825	27,088
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,648	20,648
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,953	22,953
Operable Capacity Margin	1,872	4,135

[1]Operable Capacity is based on data as of **January 20, 2020** 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 **January 20, 2020.**

[2] Load forecast that is based on the 2019 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **February 1, 2020.**

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

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

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

Winter 2019/2020 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

February 1, 2020 - 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, 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]
2/1/2020	**31029**	**412**	**1094**	**28**	**434**	**0**	**3100**	**2958**	**26071**	**19967**	**2305**	**22272**	**3799**
2/8/2020	31029	412	1094	28	246	0	3100	2647	26570	19937	2305	22242	4328
2/15/2020	31029	412	1094	28	222	164	3100	2172	26905	19664	2305	21969	4936
2/22/2020	31029	412	1094	28	101	164	3100	1705	27493	18636	2305	20941	6552
2/29/2020	31344	457	917	28	1303	0	2200	1557	27686	18273	2305	20578	7108
3/7/2020	31344	457	917	28	1260	0	2200	1246	28040	18069	2305	20374	7666
3/14/2020	31344	457	917	28	1629	647	2200	0	28270	17690	2305	19995	8275
3/21/2020	31344	457	917	28	2220	655	2200	0	27671	17102	2305	19407	8264

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
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3. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
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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)

Winter 2019/2020 Operable Capacity Analysis

90/10 Forecast (Extreme)

ISO-NE OPERABLE CAPACITY ANALYSIS

February 1, 2020 - 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, 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]
2/1/2020	**31029**	**412**	**1094**	**28**	**434**	**0**	**3100**	**4204**	**24825**	**20648**	**2305**	**22953**	**1872**
2/8/2020	31029	412	1094	28	246	0	3100	3737	25480	20617	2305	22922	2558
2/15/2020	31029	412	1094	28	222	164	3100	3262	25815	20336	2305	22641	3174
2/22/2020	31029	412	1094	28	101	164	3100	2639	26559	19277	2305	21582	4977
2/29/2020	31344	457	917	28	1303	0	2200	2336	26907	18903	2305	21208	5699
3/7/2020	31344	457	917	28	1260	0	2200	2180	27106	18693	2305	20998	6108
3/14/2020	31344	457	917	28	1629	647	2200	910	27360	18302	2305	20607	6753
3/21/2020	31344	457	917	28	2220	655	2200	435	27236	17697	2305	20002	7234

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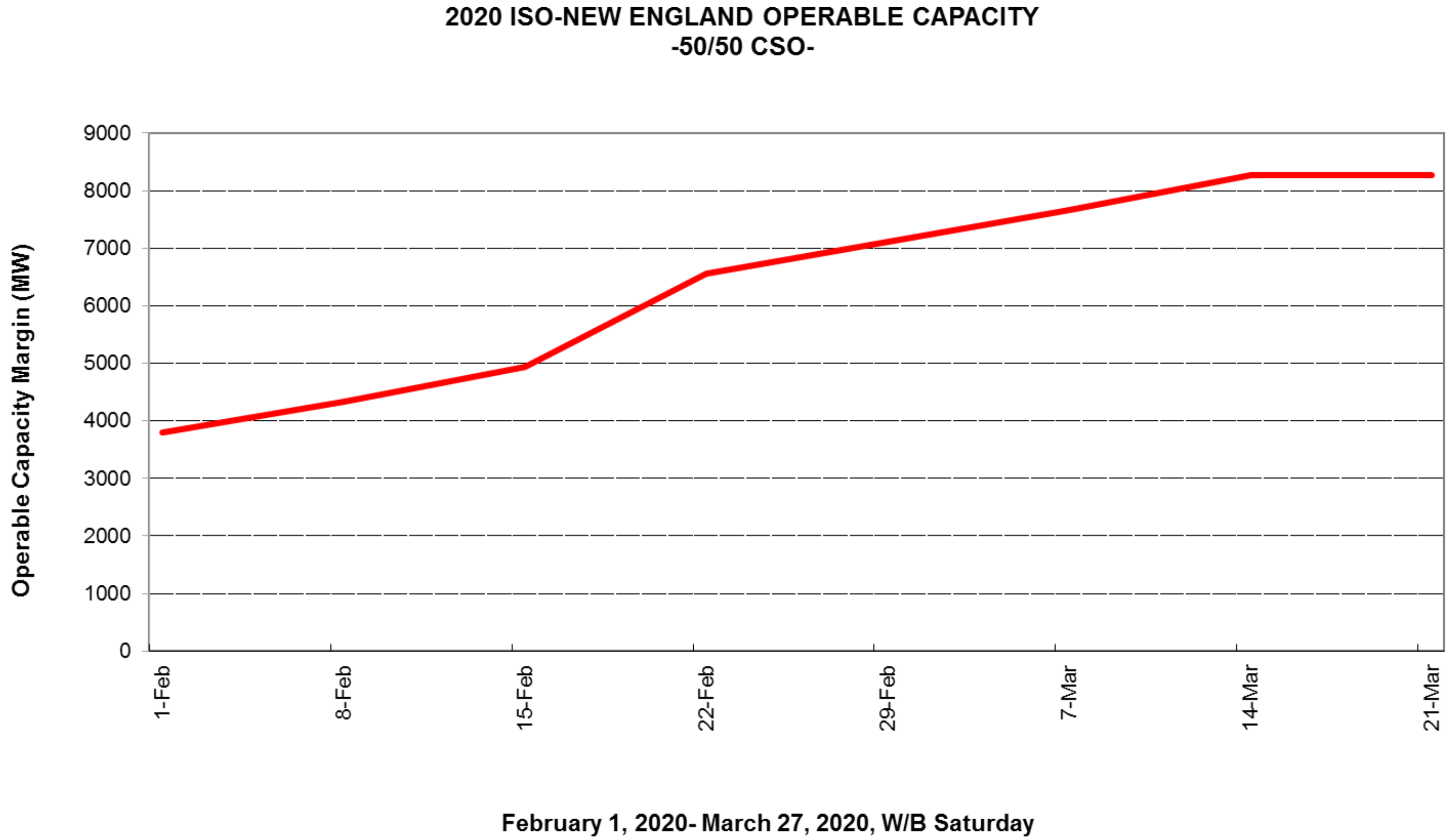
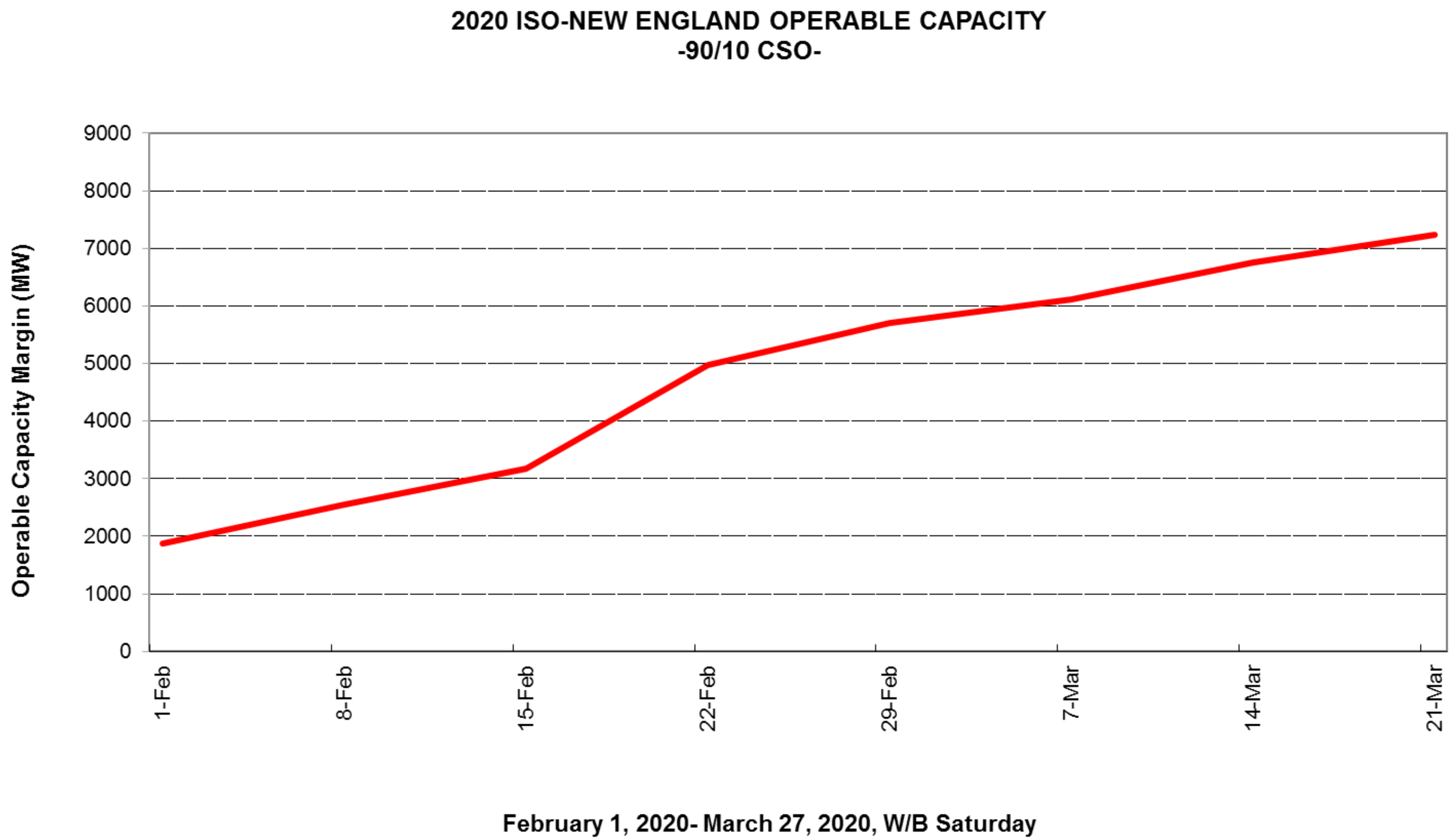
***Highlighted week is based on the week determined by the 50/50 Load Forecast Reference week**

Winter 2019/2020 Operable Capacity Analysis
50/50 Forecast (Reference)



Winter 2019/2020 Operable Capacity Analysis
90/10 Forecast (Extreme)



OPERABLE CAPACITY ANALYSIS

Preliminary Spring 2020 Analysis

Preliminary Spring 2020 Operable Capacity Analysis

50/50 Load Forecast (Reference)	May - 2020[2] CSO (MW)	May - 2020[2] SCC (MW)
Operable Capacity MW [1]	31,344	33,821
Active Demand Capacity Resource (+) [5]	453	443
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	917	917
Non Commercial Capacity (+)	28	28
Non Gas-fired Planned Outage MW (-)	5,654	5,839
Gas Generator Outages MW (-)	1,293	1,461
Allowance for Unplanned Outages (-) [4]	3,400	3,400
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	22,395	24,509
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	19,340	19,340
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	21,645	21,645
Operable Capacity Margin	750	2,864

[1]Operable Capacity is based on data as of **January 20, 2020** 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 **January 20, 2020.**

[2] Load forecast that is based on the 2019 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 9, 2020.**

[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 Spring 2020 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	May - 2020[2] CSO (MW)	May - 2020[2] SCC (MW)
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Non Commercial Capacity (+)	28	28
Non Gas-fired Planned Outage MW (-)	5,654	5,839
Gas Generator Outages MW (-)	1,293	1,461
Allowance for Unplanned Outages (-) [4]	3,400	3,400
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	22,395	24,509
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,858	20,858
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,163	23,163
Operable Capacity Margin	-768	1,346

[1]Operable Capacity is based on data as of **January 20, 2020** 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 **January 20, 2020.**

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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 Spring 2020 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

February 1, 2020 - 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, August, and Mid September

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	Active Capacity Demand MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERATOR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
3/28/2020	31344	453	917	28	4150	1039	2700	0	24853	16344	2305	18649	6204
4/4/2020	31344	453	917	28	4245	1809	2700	0	23988	16082	2305	18387	5601
4/11/2020	31344	453	917	28	4361	1797	2700	0	23884	15552	2305	17857	6027
4/18/2020	31344	453	917	28	5597	2206	2700	0	22239	15277	2305	17582	4657
4/25/2020	31344	453	917	28	5862	1422	2700	0	22758	14472	2305	16777	5981
5/2/2020	31344	453	917	28	5436	1386	3400	0	22520	18318	2305	20623	1897
5/9/2020	**31344**	**453**	**917**	**28**	**5654**	**1293**	**3400**	**0**	**22395**	**19340**	**2305**	**21645**	**750**
5/16/2020	31344	453	917	28	3420	1374	3400	0	24548	20290	2305	22595	1953
5/23/2020	31344	453	917	28	1912	267	3400	0	27163	21333	2305	23638	3525

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 Spring 2020 Operable Capacity Analysis
90/10 Forecast (Extreme)

ISO-NE OPERABLE CAPACITY ANALYSIS

February 1, 2020 - 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, August, and Mid September

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	Active Capacity Demand MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERATOR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
3/28/2020	31344	453	917	28	4150	1039	2700	0	24853	16923	2305	19228	5625
4/4/2020	31344	453	917	28	4245	1809	2700	0	23988	16654	2305	18959	5029
4/11/2020	31344	453	917	28	4361	1797	2700	0	23884	16108	2305	18413	5471
4/18/2020	31344	453	917	28	5597	2206	2700	0	22239	15824	2305	18129	4110
4/25/2020	31344	453	917	28	5862	1422	2700	0	22758	15018	2305	17323	5435
5/2/2020	31344	453	917	28	5436	1386	3400	0	22520	19768	2305	22073	447
5/9/2020	**31344**	**453**	**917**	**28**	**5654**	**1293**	**3400**	**0**	**22395**	**20858**	**2305**	**23163**	**-768**
5/16/2020	31344	453	917	28	3420	1374	3400	0	24548	21870	2305	24175	373
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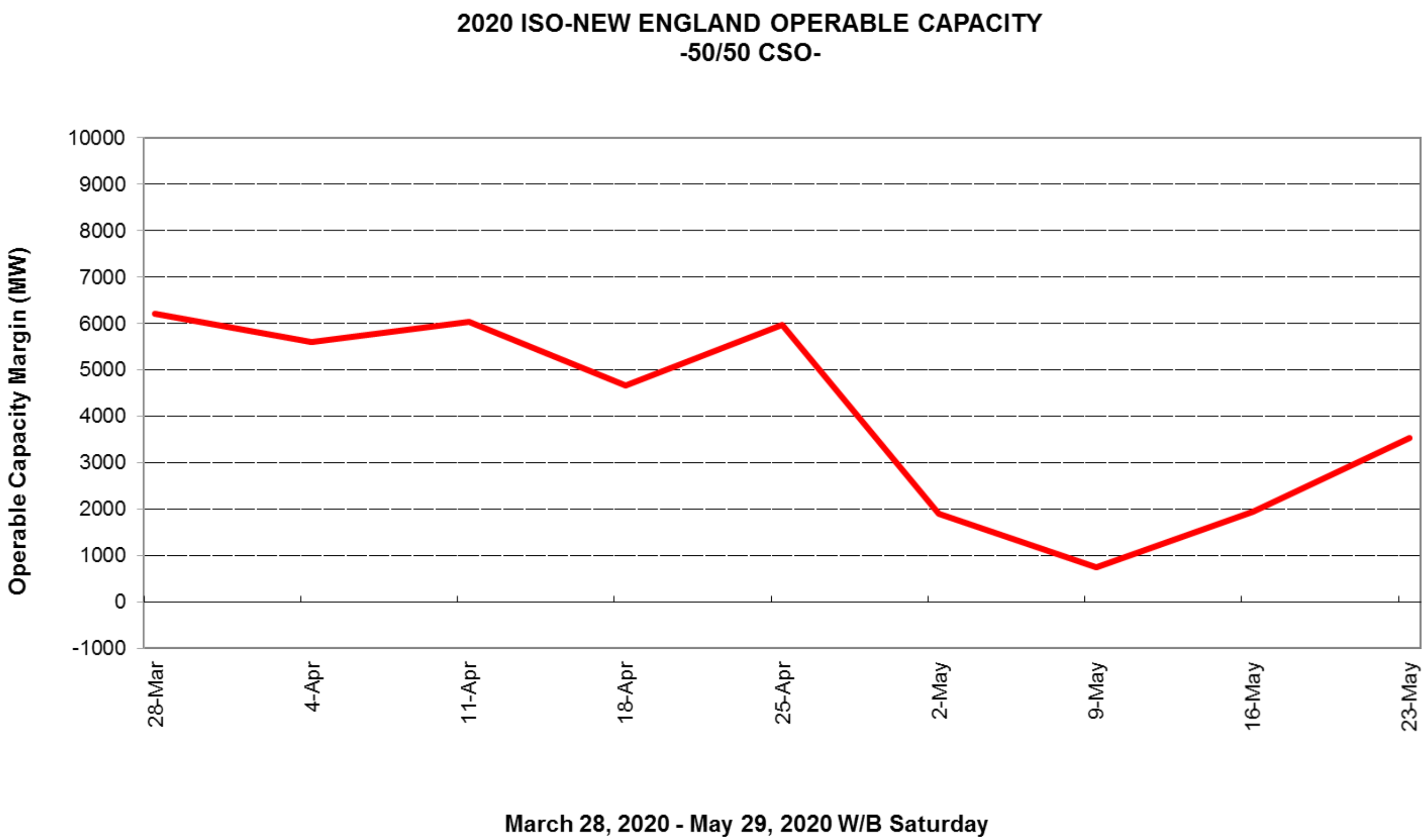
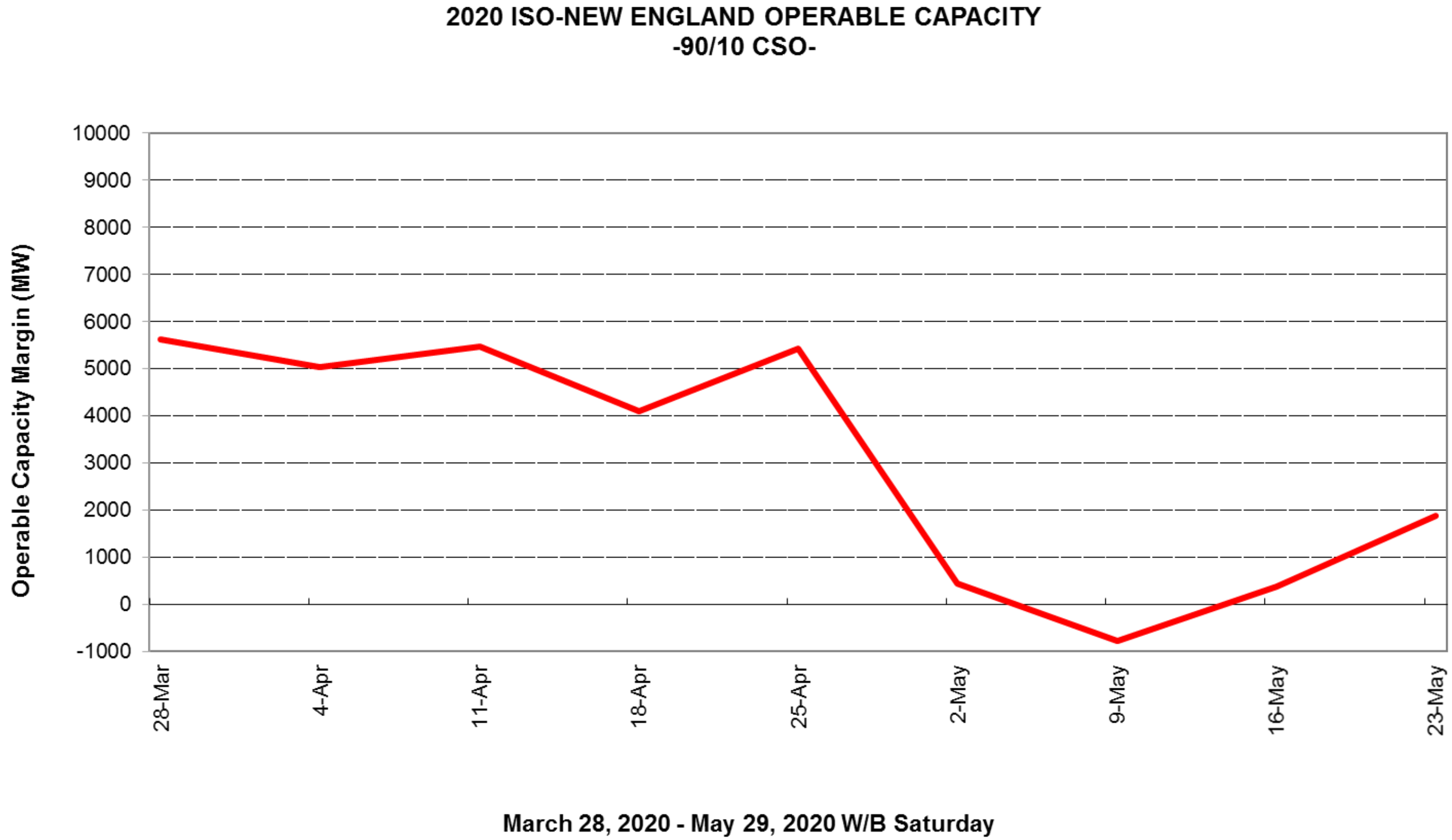
13. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (9 - 12 = 13)

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

Preliminary Spring 2020 Operable Capacity Analysis
50/50 Forecast (Reference)



Preliminary Spring 2020 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 and Rosendo Garza, Jr., NEPOOL Counsel
DATE: January 30, 2020
RE: *Order 841* Further Compliance Revisions (Elec. Storage Participation in RTO/ISO Markets)

At its February 6, 2020 teleconference meeting, the Participants Committee will be asked to consider supporting Tariff revisions proposed by the ISO in response to the FERC's November 22, 2019 Order (the "*November 22 Order*")[1] requiring further changes in New England's *Order 841* electric storage participation proceeding.[2] The Markets Committee reviewed and unanimously recommended Participants Committee support for those changes (the "*Order 841* Further Compliance Revisions"). But for the timing of the Markets Committee's consideration of and support for the *Order 841* Further Compliance Revisions, this matter would have been on the Consent Agenda.

BACKGROUND & OVERVIEW OF *ORDER 841* FURTHER COMPLIANCE REVISIONS

On December 3, 2018, the ISO and NEPOOL submitted proposed revisions to the Tariff to comply with the requirements of *Order 841*. Nearly a year later, on November 22, 2019, the FERC conditionally accepted New England's *Order 841* compliance filing, subject to a further compliance filing to address certain requirements.[3]

To address those requirements, the ISO proposed Market Rule revisions that, among other things: (1) add details in Section III.1.10.6(a) to state explicitly that Electric Storage Facilities ("ESFs")[4] shall "be directly metered"; and (2) provide clarifying Tariff revisions in Section III.1.10.6(a) stating

[1] Of note, on December 30, 2019, the Commission granted NEPOOL's request for an extension of time, until February 10, 2020, for the ISO to submit the compliance filing the Commission directed. *See* Notice of Extension of Time, Docket Nos. ER19-470-000, ER19-470-001, and ER19-470-002 (issued Dec. 30, 2019).

[2] *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 841, 162 FERC ¶ 61,127 (2018), *order on reh'g*, Order No. 841-A, 167 FERC ¶ 61,154 (2019).

[3] The ISO was directed to address the following requirements:

> 1. Revise the Tariff by: (a) explicitly stating that an Electric Storage Facility shall "be directly metered"; (b) explicitly stating that the ISO will not charge distribution-connected electric storage resources ("ESRs") for charging energy if the distribution utility is unwilling or unable to net out any energy purchases associated with an ESR's wholesale charging activities from the host customer's retail bill; and (c) including a basic description of ISO-NE's metering methodology and accounting practices for ESRs.
>
> 2. Clarify that an ESR, by registering as an asset in ISO-NE, can participate in both wholesale and retail markets, so long as the resource meets its wholesale market obligations.
>
> 3. Apply transmission charges to an ESR when that resource is charging for later resale in wholesale markets and is not providing a service, or demonstrate that exempting such a resource from these charges is reasonable.
>
> 4. Account for an ESR's state of charge, maximum and minimum state of charge, maximum run time, and maximum charge time, in the Day-Ahead Energy Market.

[4] An "ESF" is a facility that must, in addition to having the ability to both consume and supply energy, meet the qualification criteria of either or both a Binary Storage Facility or a Continuous Storage Facility. *See* Tariff, Section III.1.10.6(a) (defining an ESF).

that an ESF will not be precluded from providing retail services so long as it can meet its wholesale market obligations.[5]

In response to the FERC's directive that the Tariff account for an ESR's state of charge, maximum and minimum state of charge, maximum run time, and maximum charge time in the Day-Ahead Energy Market, the ISO filed a Request for a Rehearing, which remains pending before the FERC.[6] This request, however, does not excuse the ISO from meeting its compliance obligation. Accordingly, the ISO proposes in the *Order 841* Further Compliance Revisions to add Section III.1.10.6(d) to state that the ISO will account for an ESR's state of charge and associated characteristics.

While not proposing any additional Tariff revisions at this time, the ISO has committed to provide further explanation in its February 10 compliance filing as to why exempting ESRs from transmission charges is reasonable. The compliance filing will propose a December 3, 2019 effective date for all of the revisions, other than for the addition of Section III.1.10.6(d), which will be proposed to become effective as of January 1, 2026. Additional detail on the *Order 841* Further Compliance Revisions, including the proposed Tariff redlines, is included in background materials included with this memorandum.

Markets Committee Review

The ISO's proposal to respond to the *November 22 Order* was presented for stakeholder review and input at two Markets Committee meetings in January. At its January 28, 2020 meeting, the Markets Committee unanimously recommended Participants Committee support for the *Order 841* Further Compliance Revisions, with one abstention noted in the Supplier Sector.

As noted, the *Order 841* Further Compliance Revisions would have been on the Consent Agenda for the February 6 Participants Committee meeting but for the timing of the Markets Committee's vote.

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

> RESOLVED, that the Participants Committee support the revisions to Tariff Section III.1.10.6 and Market Rule 1 to address certain requirements set forth in the FERC's November 22, 2019 Order in Docket No. ER19-470, as recommended by the Markets Committee at its January 28, 2020 meeting and as circulated to this Committee in advance of this meeting, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

---

[5] Also, the compliance proposal adds Section III.1.10.6(e), which not only includes language that ESRs will not pay twice for the same charging energy, but also a basic description of the ISO's metering methodology and accounting practices for ESRs.

[6] *See* Request for Rehearing of ISO New England Inc., *ISO New England Inc.*, Docket No. ER19-470-003 (filed Dec. 23, 2019); Order Granting Rehearing for Further Consideration, *ISO New England Inc.*, Docket No. ER19-470-003 (Jan. 21, 2020) (affording the FERC additional time to consider the rehearing request).

III.1.10.6 Electric Storage

A storage facility is a facility that is capable of receiving electricity from the grid and storing the energy for later injection of electricity back to the grid. A storage facility may participate in the New England Markets as described below.

(a) A storage facility that satisfies the requirements of this subsection (a) may participate in the New England Markets as an Electric Storage Facility. An Electric Storage Facility shall:

(i) have the ability to inject at least 0.1 MW and consume at least 0.1 MW;

(ii) comprise one or more storage facilities at the same point of interconnection;

(iii) be directly metered;

(iv) be registered as, and subject to all rules applicable to, a dispatchable Generator Asset;

(~~iii~~v) be registered as, and subject to all rules applicable to, a DARD that represents the same equipment as the Generator Asset;

(~~i~~vi) settle its injection of electricity to the grid as a Generator Asset and its receipt of electricity from the grid as a DARD;

(vii) not be precluded from providing retail services so long as it is able to fulfill its wholesale Energy Market and Forward Capacity Market obligations including, but not limited to, satisfying meter data reporting requirements and notifying the ISO of any changes to operational capabilities; and

(viii) meet the requirements of either a Binary Storage Facility or a Continuous Storage Facility, as described in subsections (b) and (c) below.

(b) A storage facility that satisfies the requirements of this subsection (b) may participant in the New England Markets as a Binary Storage Facility. A Binary Storage Facility shall:

(i) satisfy the requirements applicable to an Electric Storage Facility;

(ii) offer its Generator Asset and DARD into the Energy Market as Rapid Response Pricing Assets; and

(iii) be issued Dispatch Instructions in a manner that ensures the facility is not required to consume and inject simultaneously.

(c) A storage facility that satisfies the requirements of this subsection (c) may participate in the New England Markets as a Continuous Storage Facility. A Continuous Storage Facility shall:

(i) satisfy the requirements applicable to an Electric Storage Facility;

(ii) be registered as, may provide Regulation as, and is subject to all rules applicable to, an ATRR that represents the same equipment as the Generator Asset and DARD;

(iii) be capable of transitioning between the facility's maximum output and maximum consumption (and vice versa) in ten minutes or less;

(iv) not utilize storage capability that is shared with another Generator Asset, DARD or ATRR;

(v) specify in Supply Offers a zero MW value for Economic Minimum Limit and Emergency Minimum Limit (except for Generator Assets undergoing Facility and Equipment Testing or auditing); a zero time value for Minimum Run Time, Minimum Down Time, Notification Time, and Start-Up Time; and a zero cost value for Start-Up Fee and No-Load Fee;

(vi) specify in Demand Bids a zero MW value for Minimum Consumption Limit (except for DARDs undergoing Facility and Equipment Testing or auditing) and a zero time value for Minimum Run Time and Minimum Down Time;

(vii) be Self-Scheduled in the Day-Ahead Energy Market and Real-Time Energy Market, and operate in an on-line state, unless the facility is declared unavailable by the Market Participant; and

(viii) be issued a combined dispatch control signal equal to the Desired Dispatch Point (of the Generator Asset) minus the Desired Dispatch Point (of the DARD) plus the AGC SetPoint (of the ATRR).

(d) In clearing the Day-Ahead Energy Market, the ISO will account for maximum run time, maximum charge time, state of charge, maximum state of charge, and minimum state of charge through bidding parameters or other means, as required by the Commission in Order No. 841.

(e) A storage facility shall comply with all applicable registration, metering, and accounting rules including, but not limited to, the following:

(i) A Market Participant wishing to purchase energy from the ISO-administered wholesale markets must first, jointly with its Host Participant, register one or more wholesale Load Assets with the ISO as described in ISO New England Manual M-28 and ISO New England Manual M-RPA; where the Market Participant wishes to register an Electric Storage Facility, the registered Load Asset must be a DARD.

(ii) A storage facility's charging load shall not qualify as a DARD if the Host Participant is unwilling or unable to support the registration, metering, and accounting of the storage facility's load as a separate and distinct Load Asset. A storage facility registered as a DARD will be charged the nodal Locational Marginal Price by the ISO and the Market Participant will not pay twice for the same charging load.

(iii) The registration and metering of all Assets must comply with ISO New England Operating Procedure No. 14 and ISO New England Operating Procedure No. 18, including with the requirement that an Asset's revenue metering must comply with the accuracy requirements found in ISO New England Operating Procedure No. 18.

(iv) Pursuant to ISO New England Manual M-28, the Assigned Meter Reader, the Host Participant, and the ISO provide the data for use in the daily settlement process within the timelines described in the manual. The data may be five-minute interval data, and may be no more than hourly data, as described in Section III.3.2 and in ISO New England Manual M-28.

(v) Based on the Metered Quantity For Settlement and the Locational Marginal Price in the settlement interval, the ISO shall conduct all Energy Market accounting pursuant to Section III.3.2.1.

~~(d)~~(f) A facility registered as a dispatchable Generator Asset, an ATRR, and a DARD that each represent the same equipment must participate as a Continuous Storage Facility.

~~(e)~~(g) A storage facility not participating as an Electric Storage Facility may, if it satisfies the associated requirements, be registered as a Generator Asset (including a Settlement Only Resource) for settlement of its injection of electricity to the grid and as an Asset Related Demand for settlement of its wholesale load.

~~(f)~~(h) A storage facility may, if it satisfies the associated requirements, be registered as a Demand Response Asset. (As described in Section III.8.1.1, a Demand Response Asset and a Generator Asset may not be registered at the same end-use customer facility unless the Generator Asset is separately metered and reported and its output does not reduce the load reported at the Retail Delivery Point of the Demand Response Asset.)

~~(g)~~(i) A storage device may, if it satisfies the associated requirements, be registered as a component of either an On-Peak Demand Resource or a Seasonal Peak Demand Resource.

~~(h)~~(j) A storage facility may, if it satisfies the associated requirements, provide Regulation pursuant to Section III.14.

memo

To: NEPOOL Markets Committee

From: Catherine McDonough

Date: January 22, 2020

Subject: Further Compliance Revisions associated with FERC Order No. 841

The ISO is requesting a vote on its proposed Market Rule 1 revisions which address the further compliance directives contained in the Commission's November 22, 2019 order[1] in the Electric Storage Participation proceeding.[2] By way of background, the Commission's November 22, 2019 order accepted the ISO's Order No. 841 compliance filing subject to an additional compliance filing to address four issues. These issues include:

(1) Add Tariff language to describe the metering and accounting rules applicable to electric storage resources.
(2) Clarify that Electric Storage Facilities (ESFs) are not precluded from providing retail service.
(3) Apply transmission charges to ESFs when they are charging and not providing a service or demonstrate that it is reasonable not to do so.
(4) Account for state of charge and duration characteristics of an ESF in the Day-Ahead Energy Market.

The responses that the ISO plans to submit to address these issues fully align with the filing submitted by the ISO, NEPOOL and the PTO-AC on December 3, 2018.

The proposed Market Rule 1 revisions to address issue (1) add detail with regard to the metering and accounting rules that apply to electric storage resources, including adding language to ensure electric storage resources do not pay twice for the same charging energy. The proposed Market Rule change to address issue (2) clarifies that an ESF can also provide retail services as long as it can meet its wholesale market obligations.

Regarding issue (3), the ISO will expand on its explanation regarding why exempting ESFs from transmission charges is justified given the policy direction set out in Order No. 841 and Order No. 841-A.[3]

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[1] *See ISO New England Inc.,* 169 FERC ¶ 61,140 (2019) ("November 22, 2019 order").
[2] *See ISO New England Inc. and New England Power Pool,* Revisions to ISO New England Inc. Transmission Markets and Services Tariff in Compliance with FERC Order 841, Docket Nos. ER19-470-000, ER19-470-001, and ER19-470-002 (filed December 3, 2018).
[3] *See ISO New England Inc.,* 167 FERC ¶ 61,154 (2019).

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One Sullivan Road
Holyoke, MA 01040-2841

Regarding issue (4), on December 23, 2019 the ISO submitted a request for rehearing with the Commission on this requirement.[4] Because filing for rehearing does not waive the associated compliance obligation, the ISO will propose a compliant revision to Market Rule 1. Although we are hopeful that the Commission will grant the request for rehearing, the ISO will assess and discuss design details related to this Tariff revision with stakeholders ahead of any implementation if the rehearing petition is denied.

The specific proposal for the committee's consideration at its January 28, 2020 meeting has been presented previously to the Markets Committee at the meeting dates outlined below.

- December 10-11, 2019, agenda item 3: https://www.iso-ne.com/event-details?eventId=137585
- January 14-15, 2020, agenda item 3: https://www.iso-ne.com/event-details?eventId=140254

[4] *See ISO New England Inc.,* Request for Rehearing of ISO New England Inc., Docket Nos. ER19-470-000, ER19-470-001, and ER19-470-002 (filed December 23, 2019).

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JANUARY 28, 2020| NEPOOL MARKETS COMMITTEE

Revision 1

FERC Order No. 841 Compliance

Electric Storage Participation in Markets

Revision 1:

-Effective date correction - slide 7

Catherine McDonough

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FERC Order No. 841 Compliance

WMPP ID: 129

Filing Deadline: February 10, 2020

- FERC Order No. 841 requires ISOs to establish a "participation model"(i.e., market rules) that facilitates the participation of electric storage resources in RTO/ISO markets
  - Effective date for the Order: December 3, 2019
- On November 22, 2019, FERC approved ISO New England's Order No. 841 compliance filing subject to an additional compliance filing to address four issues:
  1) Add Tariff language to describe the metering and accounting rules applicable to electric storage resources
  2) Clarify that Electric Storage Facilities (ESFs) are not precluded from providing retail service
  3) Apply transmission charges to ESFs when they are charging and not providing a service or demonstrate that it is reasonable not to do so
  4) Account for state of charge and duration characteristics of an ESF in the Day-Ahead Energy Market
- Today: Address stakeholder questions related to issue #2 and vote on tariff changes to address issues #1, #2 and #4

FERC Order No. 841 Compliance Requirement #2

Tariff Change to indicate that ESFs can also provide retail services

Requirement #2: Clarify that, by registering as an asset in ISO-NE, an ESF is not precluded from providing retail service, so long as the resource meets its wholesale market obligations

Response: Add item (vii) to Section III.1.10.6 (a)

An Electric Storage Facility shall:

(vii) not be precluded from providing retail services so long as it is able to fulfill its wholesale Energy Market and Forward Capacity Market obligations including, but not limited to, satisfying meter data reporting requirements and notifying the ISO of any changes to operational capabilities;

Stakeholder Questions from January 14, 2020 MC Meeting:

- Do we need more rules to ensure that an Electric Storage Facility that provides a retail service also meets its wholesale market obligations, or to ensure correct retail accounting?
- How can we be sure that an Electric Storage Facility is not unjustifiably exempted from wholesale market costs (i.e. FCM, transmission, etc.) when it provides a retail service?

FERC Order No. 841 Compliance Requirement #2

Response to Stakeholder Questions: No Additional Rules Required

- Section 1.10.6 of Market Rule 1 requires that an ESF be directly metered and registered as, and subject to all of the rules of a Dispatchable Asset Related Demand (DARD) and Generator Asset
  - A Continuous Storage Facility must further register in the wholesale market as an Alternative Technology Regulation Resource (ATRR)
- Like any DARD and Generator Asset, an ESF must be dispatched by the ISO to consume or discharge in the wholesale market (based on its economic offer or self-dispatch request) and is required to follow its Dispatch Instruction
- An ESF that follows a Dispatch Instruction to charge or discharge and meets all other wholesale market obligations (e.g. meter data reporting, ISO notification, etc.) can, like any Generator Asset, **simultaneously** provide a retail service such as local transmission and distribution (T&D) relief, local voltage support, or output to support a retail contract, etc.

FERC Order No. 841 Compliance Requirement #2

Response to Stakeholder Questions (continued)

- Like any Generator Asset, an ESF that does not meet its wholesale market obligations will incur financial settlement consequences (e.g. Net Commitment Period Compensation (NCPC) cost allocation, Forward Capacity Market (FCM) performance penalties, reduced regulation market compensation)
- An ESF that provides a retail service should still be exempt from certain wholesale market costs (e.g. FCM, transmission, etc.) because the provision of a retail service is incidental to the ESF meeting its wholesale market obligation (including following a Dispatch Instruction to charge) for which an exemption from wholesale market costs has been established
- Note: Even when an ESF provides output to support a retail contract (as it follows a wholesale Dispatch Instruction to discharge), the wholesale Load Asset associated with that retail contract is still subject to an allocation of wholesale market costs (i.e. FCM, transmission, etc.)

Conclusion

- The ISO's further compliance with FERC Order No. 841 addresses the four issues that required additional action
- At the January 28, 2020 Markets Committee meeting, the committee will vote on the ISO's proposed Tariff compliance revision
  - Please note that ISO will strive to finalize the tariff changes before the MC vote, but as the ISO works to prepare the compliance package following the vote, it may turn out that the language requires additional refinement; should this occur, the ISO will inform NEPOOL of any changes
- The Participants Committee will consider this item at its February 6, 2020 meeting
- The ISO plans to file its further compliance revisions with FERC by February 10, 2020

*Revision 1:
Effective date correction*

Stakeholder Schedule

Stakeholder Committee and Date	Scheduled Project Milestone
Markets Committee December 10-11, 2019	Initial discussion of FERC order on further compliance with Order No. 841
Markets Committee January 14-15, 2020	Discussion and review of tariff revisions
Markets Committee January 28, 2020	MC Vote
Participants Committee February 6, 2020	PC Vote
February 10, 2020	FERC filing

Effective Date: ~~April 11, 2020~~ December 3, 2019 for all but the addition of Section III.1.10.6 (d), which will have an effective date of January 1, 2026

Questions

APPENDIX: MATERIALS FROM JANUARY 14TH 2020 MC MEETING

FERC Order No 841 Compliance Requirements

FERC Order No. 841 Compliance Requirement #1

Tariff Language to Describe Metering and Accounting Rules

Requirement #1A: Add explicit statement in Market Rule 1, Section III.1.10.6 (a) that an Electric Storage Facility shall "be directly metered"

Response: Add language in quotes as Section III.1.10.6 (a) (iii)

Requirement #1B: Add Tariff language to demonstrate that electric storage resources will not pay twice for the same charging energy

Response: Add Section III.1.10.6 (e)(ii), see slide #17

FERC Order No. 841 Compliance Requirement #1 *(cont.)*

Tariff Language to Describe Metering and Accounting Rules

Requirement #1C: Add Tariff language to include a basic description of ISO-NE's metering methodology and accounting practices for ESFs including references to ISO-NE's business practice manuals or other documents that contain implementation detail

Response: Add Section III.1.10.6.(e), see slide #17

FERC Order No. 841 Compliance Requirement #3

Demonstrate that Transmission Cost Exemption Always Complies

Requirement #3: Demonstrate that an ESF will be subject to transmission charges when it is charging and not providing a tariff-defined service or that it is otherwise reasonable to exempt an ESF from transmission costs whenever it charges given the existing rate structure for transmission charges.

Response:

- Electric Storage Facilities are not subject to the transmission charges (as described in OATT, Section II.21.1, Schedule 9 and Schedule 21) because they are nearly always providing a wholesale market service when they are charging (e.g. reserve, regulation, VAR or frequency response)
- On the rare occasion when they are not providing a service when charging, the exemption is reasonable given the existing rate structure for transmission charges in New England

FERC Order No. 841 Compliance Requirement #3

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Response:

- Electric Storage Facilities are not subject to the transmission charges (as described in OATT, Section II.21.1, Schedule 9 and Schedule 21) because they are nearly always providing a wholesale market service when they are charging (e.g. reserve, regulation, VAR or frequency response)
- On the rare occasion when they are not providing a service when charging, the exemption is reasonable given the existing rate structure for transmission charges in New England

FERC Order No. 841 Compliance Requirement #4

Tariff Change to Account for Physical and Operating Characteristics

Requirement #4: ISO must modify its existing participation model to account for Maximum Run Time, Maximum Charge Time, State of Charge, Maximum State of Charge, and Minimum State of Charge through bidding parameters or other means in its day-ahead energy market as required by Order No. 841.

Response: On Dec. 23, the ISO filed a Request for Rehearing on this requirement. However, doing so does not waive the compliance requirement. Therefore, on compliance, the ISO will add:

> Section III.1.10.6 (d)
> In clearing the Day-Ahead Energy Market, the ISO will account for maximum run time, maximum charge time, state of charge, maximum state of charge, and minimum state of charge through bidding parameters or other means, as required by the Commission in Order No. 841.

If the Request for Rehearing is denied, the ISO will discuss with stakeholders the details of how we will enable participants to further account for these physical and operational characteristics in the day-ahead energy market

TARIFF CHANGES

FERC Order No 841 Compliance Requirements

Tariff Changes in Response to FERC's Compliance Order

III.1.10.6 Electric Storage

A storage facility is a facility that is capable of receiving electricity from the grid and storing the energy for later injection of electricity back to the grid. A storage facility may participate in the New England Markets as described below.

(a) A storage facility that satisfies the requirements of this subsection (a) may participate in the New England Markets as an Electric Storage Facility. An Electric Storage Facility shall:

- (i) have the ability to inject at least 0.1 MW and consume at least 0.1 MW;
- (ii) comprise one or more storage facilities at the same point of interconnection;
- (iii) be directly metered; — Issue #1A
- (iv) be registered as, and subject to all rules applicable to, a dispatchable Generator Asset;
- (~~iii~~v) be registered as, and subject to all rules applicable to, a DARD that represents the same equipment as the Generator Asset;
- (~~i~~vi) settle its injection of electricity to the grid as a Generator Asset and its receipt of electricity from the grid as a DARD;
- (vii) not be precluded from providing retail services so long as it is able to fulfill its wholesale Energy Market and Forward Capacity Market obligations including, but not limited to, satisfying meter data reporting requirements and notifying the ISO of any changes to operational capabilities; and — Issue #2
- (viii) meet the requirements of either a Binary Storage Facility or a Continuous Storage Facility, as described in subsections (b) and (c) below.

(d) In clearing the Day-Ahead Energy Market, the ISO will account for maximum run time, maximum charge time, state of charge, maximum state of charge, and minimum state of charge through bidding parameters or other means, as required by the Commission in Order No. 841. — Issue #4

Tariff Changes in Response to FERC's Compliance Order *(cont.)*

(e) A storage facility shall comply with all applicable registration, metering, and accounting rules including, but not limited to, the following:

(i) A Market Participant wishing to purchase energy from the ISO-administered wholesale markets must first, jointly with its Host Participant, register one or more wholesale Load Assets with the ISO as described in ISO New England Manual M-28 and ISO New England Manual M-RPA; where the Market Participant wishes to register an Electric Storage Facility, the registered Load Asset must be a DARD.

(ii) A storage facility's charging load shall not qualify as a DARD if the Host Participant is unwilling or unable to support the registration, metering, and accounting of the storage facility's load as a separate and distinct Load Asset. A storage facility registered as a DARD will be charged the nodal Locational Marginal Price by the ISO and the Market Participant will not pay twice for the same charging load.

(iii) The registration and metering of all Assets must comply with ISO New England Operating Procedure No. 14 and ISO New England Operating Procedure No. 18, including with the requirement that an Asset's revenue metering must comply with the accuracy requirements found in ISO New England Operating Procedure No. 18.

(iv) Pursuant to ISO New England Manual M-28, the Assigned Meter Reader, the Host Participant, and the ISO provide the data for use in the daily settlement process within the timelines described in the manual. The data may be five-minute interval data, and may be no more than hourly data, as described in Section III.3.2 and in ISO New England Manual M-28.

(v) Based on the Metered Quantity For Settlement and the Locational Marginal Price in the settlement interval, the ISO shall conduct all Energy Market accounting pursuant to Section III.3.2.1.

Issue #1B

Issue #1C

Acronyms Used in the Presentation

- ESF- Electric Storage Facility
- FERC- Federal Energy Regulatory Commission
- FCM – Forward Capacity Market
- ISO- Independent System Operator
- MC- Markets Committee
- PC – Participants Committee
- RTO – Regional Transmission Organization
- TC – Transmission Committee

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of February 4, 2020

The following activity, as more fully described in the attached litigation report, has occurred since the report dated January 7, 2020 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	206 Investigation: ISO-NE Implementation of *Order 1000* Exemptions for Immediate Need Rel. Projects (EL19-90)	Jan 13 Jan 24-27	NEPOOL comments on ISO-NE Dec 27 responses to *October 17 Order* Avangrid, Eversource, LSPower, MMEWC, National Grid, NESCOE, CT PURA, State Agencies, Developers Advocating Transmission Advancements, EEI submit comments on ISO-NE responses
	2	RTO Insider Press Policy Complaint (EL18-196)	Jan 23	FERC denies rehearing of *RTO Insider Complaint Order*
	3	RNS/LNS Rates and Rate Protocols Settlement Proceeding (EL16-19-002)	Jan 22 Jan 24	TOs request procedural schedule be suspended for an add'l 90 days Chief Judge Cintron issues an order holding the proceeding in abeyance until Apr 22, 2020; TOs next status report due on or before Mar 9, 2020
	4	Base ROE Complaints I-IV: (EL11-66, EL13-33; EL14-86; EL16-64)	Jan 21	CAPs, EMCOS oppose TOs Dec 23 request to re-open the record and their Supplemental Brief

II. Rate, ICR, FCA, Cost Recovery Filings

	7	Att. F Modification: Inclusion of UI's Pequonnock Substation Project CWIP (ER20-499)	Jan 28	FERC accepts modifications, eff. Jan 31, 2020
	10	MPD OATT 2018 Annual Info Filing (ER15-1429-010)	Jan 23	Settlement Judge Dring issues status report advising that an offer of settlement is being finalized and recommending settlement judge procedures be continued

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

*	11	ISO-NE eTariff Versioning True-Up (ER20-763)	Jan 9 Jan 24	ISO-NE files corrections to remove from the version of § III.13.2 accepted with the PRD Clean-Up Changes (ER20-140) changes submitted with still-pending Fuel Security Retention Limit Revisions (ER20-89) NEPOOL intervenes
*	11	ISO-NE Waiver Request: FCA15 De-List Bids Submission Deadline (ER20-759)	Jan 8 Jan 9-Feb 3	ISO-NE requests limited waiver of Tariff § III.13.1.10(b) to allow Market Participants to adjust or withdraw their FCA15 De-List Bids under certain conditions NEPOOL, Calpine, Dominion, Eversource, Exelon, National Grid, NESCOE, NRG intervene doc-lessly
	12	Fuel Security Retention Sunset (ER20-645)	Jan 9 Jan 24	Exelon protests filing; MMWEC, NHEC intervene NEPOOL, ISO-NE answer Exelon protest
	12	Waiver Request: FCA14 Qualification (Genbright II) (ER20-366)	Feb 3	FERC denies waiver request
	13	Fuel Security Retention Limit Revision (ER20-89)	Jan 27	Exelon protests ISO-NE's Jan 6 responses to deficiency letter

	14	*Order 841* Compliance Filing (ER19-470)	Jan 21	FERC issues tolling order affording it add'l time to consider ISO-NE's request for rehearing of the *Order 841 Initial Compliance Filing Order*
	20	CONE & ORTP Updates (ER17-795)	Jan 24	FERC denies reh'g of its Oct 6, 2017 *CONE/ORTP Updates Order*

IV. OATT Amendments / TOAs / Coordination Agreements

	20	CIP IROL Cost Recovery Rules (ER20-739)	Jan 22	NEPOOL submits comments
			Jan 27	Calpine, Cross-Sound Cable, IROL-Critical Facility Owners support, and NESCOE conditionally supports, Rules
			Jan 13-27	Brookfield, Dominion, Eversource, Exelon, MA AG, National Grid, NextEra, PSEG, UI, MA DPU, MPUC, Public Citizen, RESA intervene doc-lessly
	21	Interconnection Service Capability Changes (ER20-450)	Jan 14	FERC accepts changes, eff. Jan 22, 2020

V. Financial Assurance/Billing Policy Amendments

	22	NCFA Rate (ER20-395)	Jan 14	FERC accepts NCFA Rate changes, eff. Jan 15, 2020

VI. Schedule 20/21/22/23 Changes

	23	Schedule 22: Notice of Cancellation of First Revised Clear River LGIA (ER20-586)	Jan 16	FERC accepts notice of cancellation, eff. Nov 25, 2019
	23	Schedule 20A-EM: Expiration of Talen IRH Rights Assignment (ER20-375)	Jan 15	FERC accepts changes, eff. Nov. 1, 2020
	23	Schedule 21-EM: 2018 Annual Update Settlement Agreement (ER15-1434-003)	Jan 8	FERC accepts Settlement Agreement

VII. NEPOOL Agreement/Participants Agreement Amendments

*	24	132nd Agreement (Press Membership) (ER18-2208)	Jan 23	FERC dismisses request for rehearing of *Press Membership Provisions Order*

VIII. Regional Reports

*	25	Transmission Projects Annual Info Filing (ER13-193)	Jan 31	ISO-NE files annual informational filing of projects on the RSP project list that had a year of need 3 years or less from the completion of the Needs Assessment as required under OATT § 4.1(j)(iii)
*	25	LFTR Implementation: 45th Quarterly Status Report (ER07-476)	Jan 15	ISO-NE files its 45th quarterly report

IX. Membership Filings

*	26	February 2020 Membership Filing (ER20-923)	Jan 31	***Memberships***: Avangrid Networks; TrueLight Commodities; and Weaver Wind; ***Terminations***: Great Eastern Energy, Precept Power, and the TransCanada Companies; ***Name Change*** Mercuria Energy America, LLC (f/k/a Mercuria Energy America, Inc.); comment date Feb 21
	26	December 2019 Membership Filing (ER20-493)	Jan 27	FERC accepts Dichotomy Collins Hydro LLC's membership, eff. Dec 1, 2019

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

	27	*Retirements NOPR* (Standards Efficiency Review) (RM19-17; RM19-16)	Jan 23	FERC issues *Retirements NOPR* proposing to retire 74/77 of the requirements proposed by NERC, seeking add'l information before deciding on 2; and remanding 1; comment date [60 days after publication in the *Federal Register*]
	27	*Order 867* - Revised Reliability Standard: TPL-001-5 (RM19-10)	Jan 23	FERC approves revised TPL-001-5, eff. [60 days after publication in the *Federal Register*]
	28	*Order 866* - New Reliability Standard: CIP-012-1 (RM18-20)	Jan 23	FERC approves new CIP-012-1, eff. [60 days after publication in the *Federal Register*]
	28	5-Year ERO Performance Assessment Report (RR19-7)	Jan 23	FERC conditionally accepts Report, subject to 90-day and 180-day compliance filings

XI. Misc. - of Regional Interest

	28	203 Application: CMP/NECEC (EC20-24)	Jan 8	CMP supplements application with corrections to accounting entries attached to original application
	29	203 Application: Verso/Pixelle (EC20-20)	Jan 17	FERC authorizes sale
	32	EMM Contract (ER20-619)	Feb 4	FERC accepts EMM contract
	29	PJM MOPR-Related Proceedings (EL18-178; EL16-49)	Jan 17-24	Over 50 Parties request rehearing and/or clarification of the FERC's *Dec 2019 PJM MOPR Order*
			Feb 3	Talen PJM Companies reply to PJM IMM request for rehearing
	33	D&E Agreement: CL&P/CPV Towantic (ER20-521)	Jan 22	FERC accepts D&E Agreement, eff. Dec 5, 2019
	33	Mystic COS Agreement Amendment No. 1 (ER19-1164)	Jan 9	FERC rejects Amendment No. 1
*	33	FERC Enforcement Action: Exelon Generation Co. (IN20-3)	Jan 10	FERC approves Stipulation and Consent Agreement with ExGen, requiring ExGen to pay a ***$32,500 civil penalty*** and to ***disgorge $101,156***, plus interest, to resolve the FERC's investigation into misrepresentations to ISO-NE, between 2014 and 2016, of the type and quantity of Mystic 7's start-up fuel
*	34	FERC Enforcement Action: Emera ISO-NE Tariff Violations (IN20-2)	Jan 10	FERC approves Stipulation and Consent Agreement with Emera, requiring Emera to pay a ***$5,000 civil penalty*** and to ***disgorge $14,120***, plus ***$2,002.19 in interest***, to resolve the FERC's investigation into Emera violations of the ISO-NE Tariff (submission of Rumford FPA Requests using affiliate rather than arm's length transaction data)

XII. Misc. - Administrative & Rulemaking Proceedings

35	Credit Reforms in Organized Wholesale Markets (AD20-6)	Jan 24	IRC submits comments, proposing an alternative approach to the one proposed by Energy Trading Institute
35	*Order 865*: Civil Monetary Penalty Inflation Adjustments (RM19-9)	Jan 14	*Order 865*, which increased the maximum civil monetary penalties that FERC may assess, became effective
38	*Order 864*: Public Util. Trans. ADIT Rate Changes (RM19-5)	Jan 21	FERC issues tolling order affording it additional time to consider requests for rehearing of *Order 864*; VTransco requests extension of time, to Jul 31, 2020, to submit its compliance filings
		Feb 3	FERC grants VTransco extension of time, as requested

40	*Order 860*: Data Collection for Analytics & Surveillance and MBR Purposes (RM16-17)	Jan 10	FERC issues notice that updated Data Dictionary versions and the test environment for the MBR Database are available
		Jan 22	FERC issues notice of Feb 27, 2020 workshop
41	NOI: FERC's ROE Policy (PL19-4)	Jan 31	SPP transmission owners submit comments in light of *Opinion 569*

XIII. Natural Gas Proceedings

No Activity to Report

XIV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XV. Federal Courts

48	ISO-NE's Inventoried Energy Program (Chapter 2B) Proposal (19-1224)***	Jan 13	FERC submits motion asking for 60 days between filing of Petitioners' opening brief and the FERC's brief in response
		Jan 17	FERC files Certified Index to the Record
		Jan 21	Court grants NEPOOL, ISO-NE, NEPGA, Calpine, MPUC interventions
48	*Order 841* (19-1142, 19-1147) (consol.)	Jan 23	Engie Storage Services, Vivant Solar, Tesla and Sunrun file notice of intention to participate as *Amicus Curiae*
		Jan 31	FERC files Appellee Brief
49	PG&E Bankruptcy (19-71615) (9th Cir.)	Jan 17	PG&E submits Reply Brief
49	First Energy Solutions Bankruptcy (18-3787) (6th Cir.)	Jan 27	FERC petitions 6th Circuit for *en banc* rehearing of the Dec 12 decision

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: February 4, 2020

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 February 4, 2020. If you have questions, please contact us.

I.Complaints/Section 206 Proceedings

- **206 Investigation: ISO-NE Implementation of Order 1000 Exemptions for Immediate Need Reliability Projects (EL19-90)**

As previously reported, the FERC instituted a proceeding under FPA Section 206 on October 17, 2019 to consider whether ISO-NE may be implementing exemptions for immediate need reliability projects in a manner that is inconsistent with what the FERC directed pursuant to *Order 1000*, and therefore may be unjust and unreasonable, unduly preferential and discriminatory.[2] The FERC noted that, "based on its review of the annual informational filings and materials provided in stakeholder processes as posted on the Responding RTOs' websites, we are concerned that the Responding RTOs may be implementing the exemption in a manner that is inconsistent with or more expansive than what the Commission directed."[3] The FERC directed ISO-NE to respond to questions in the *October 17 Order* to: (1) demonstrate how it is complying with the immediate need reliability project criteria; (2) demonstrate that the provisions in the Tariff, as implemented, containing certain exemptions to the requirements of *Order 1000* for immediate need reliability projects remain just and reasonable; and (3) consider additional conditions or restrictions on the use of the exemption for immediate need reliability projects to appropriately balance the need to promote competition for transmission development and avoid delays that could endanger reliability. ISO-NE's response was due and was filed on December 27, 2019. The FERC noted its expectation that it would issue a final order within six months of ISO-NE's response.[4] On October 18, the FERC issued a notice of the proceeding and of the refund effective date, which will be October 28, 2019 (the date the *October 17 Order* was published in the *Federal Register*).

Those interested in participating in this proceeding were required to intervene on or before November 27, 2019.[5] Interventions were filed by: NEPOOL, ISO-NE, Anbaric, Avangrid, Calpine, CT AG, CT, OCC, CT PURA, ENE, Eversource, IECG, LSPower, MA AG, MA DPU, MMWEC, MS PSC, NESCOE, NHEC, NextEra, NRDC, NRG, PSEG, AK PSC, ATC, Developers Advocating Transmission Advancements, East TX Cooperative, EEI, IECA, LA

[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] *ISO New England Inc. et al.*, 169 FERC ¶ 61,054 (Oct. 17, 2019) ("*October 17 Order*").

[3] *Id.* at P 7.

[4] *Id.* at P 23.

[5] The *October 17 Order* was published in the *Fed. Reg.* on Oct. 29, 2019 (Vol. 84, No. 208) pp. 57,726-57,727.

PSC, MD PSC, Mid-Kansas Electric Co., NJ PBU, NY TOs, NY Transco, Northeast TX Electric Cooperative, PA PUC, Public Citizen, Sunflower Electric Cooperative, and Xcel Energy Services. As noted above, ISO-NE submitted its responses on December 27, 2019.

Comments on ISO-NE's response are due on or before January 27, 2020 and were filed by: NEPOOL, Avangrid, Eversource, LSPower, MMEWC, National Grid, NESCOE, CT PURA, State Agencies,[6] Developers Advocating Transmission Advancements, and EEI.

As noted above, a FERC order in this proceeding is expected by the end of June 2020. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **RTO Insider Press Policy Complaint (EL18-196)**

On January 23, 2020, the FERC denied rehearing[7] of its April 10, 2019 order dismissing *RTO Insider*'s August 31 Complaint.[8] 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, 2019, Public Citizen requested rehearing of the *RTO Insider Complaint Order*. As explained more fully in the *RTO Insider Complaint Rehearing Order,* the FERC was not persuaded by Public Citizen's assertions of "errors of fact" and denied rehearing. Absent a challenge in Federal Court, this proceeding will be concluded. 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).

- **Energy Security Improvements (Chapter 3) (EL18-182)**

As previously reported, the July 2, 2018 *Mystic Waiver Order*[9] (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 time, to and including October 15, 2019, a month earlier than requested, for the filing of that Proposal. The deadline has since been further extended – to ***April 15, 2020***.[10] Markets Committee consideration of ISO-NE's Energy Security Improvements ("ESI") project is on-going. If you have any questions concerning this proceeding,

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[6] "State Agencies" are: the CT and MA Attorneys General, CT DEEP, CT OCC, and MOPA.

[7] *RTO Insider LLC v. New England Power Pool Participants Comm.*, 170 FERC ¶ 61,035 (Jan. 23, 2020) ("*RTO Insider Complaint Rehearing Order*").

[8] *RTO Insider LLC v. New England Power Pool Participants Comm.*, 167 FERC ¶ 61,021 (Apr. 10, 2019) ("*RTO Insider Complaint Order*"), *reh'g denied*, 170 FERC ¶ 61,035 (Jan. 23, 2020).

[9] *ISO New England Inc.*, 164 FERC ¶ 61,003 (July 2, 2018), *reh'g requested* ("*Mystic Waiver Order*").

[10] Notice of Extension of Time, *ISO New England Inc.*, Docket No. EL18-182 (Aug. 30, 2019).

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)**

As described below, the procedural schedule in this proceeding is now suspended until April 22, 2020 to "allow the active participants to continue to work together to finalize the details of a formal offer of settlement and promote the efficient use of resources by avoiding litigation." In the absence of a settlement filing, the TOs will next file a status report with the Presiding Judge and Settlement Judge on March 9, 2020.

2018 Settlement (Rejected). Concluding that the contested 2018 Joint Offer of Settlement (the "Settlement"),[11] filed to resolve all issues in the Section 206 proceeding instituted by the FERC on December 28, 2015,[12] lacked sufficient detailed information to enable it to apply any of the approaches available to it to approve a contested settlement,[13] the FERC rejected the Settlement and remanded this proceeding (EL16-19) to Chief Judge Cintron to resume hearing procedures.[14]

As previously reported, the Settlement was supported by ***NESCOE*** but opposed by Municipal PTF Owners[15] 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,[16] 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

[11] 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.

[12] *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.

[13] 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).

[14] *ISO New England Inc. Participating Transmission Owners Admin. Comm., et al.*, 167 FERC ¶ 61,164 (May 22, 2019) ("*RNS Rate/Rate Protocol Settlement Order*").

[15] "Municipal PTF Owners" are: Braintree, Chicopee, Middleborough, Norwood, Reading, Taunton, and Wallingford.

[16] 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).

result in unreasonable rates and contains fundamental defects",[17] 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."[18] ***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.[19]

Hearings. On May 23, 2019, 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.[20] 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 has since been extended three times by a total of 85 days and is currently suspended (*see* immediately below).

Procedural Schedule Suspended Until April 22, 2020. On January 22, 2020, the TOs requested the suspension of the procedural schedule for an additional 90 days. Chief Judge Cintron issued an order on January 24, 2020 holding the proceedings in abeyance until April 22, 2020. The TOs must file a status report with the Chief Judge and Presiding Judge by March 9, 2020. As previously noted, if the current suspension period concludes without a settlement filed, the Chief Judge and Presiding Judge will take action to re-establish a procedural schedule absent good cause provided for a further suspension.

If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@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,[21] 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*

[17] 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.

[18] Reply Comments of NESCOE, Docket Nos. ER18-2235 and EL16-19, at p. 2 (filed Sep. 28, 2018).

[19] Reply Comments of the Mass. Att'y General in Support of Settlement, Docket Nos. EL16-19 and ER18-2235 (filed Sep. 28, 2018).

[20] Track III time standards require a hearing be convened within 42 weeks and an initial decision issued within 63 weeks.

[21] 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*")).

531-A).[22] However, the FERC's orders were challenged, and in *Emera Maine,*[23] 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)[24] and third (EL14-86)[25] 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.[26] The *Initial Decision* also lowered the ROE ceilings. Parties to these proceedings filed briefs on exception to the FERC, which has not yet issued an opinion on the ALJ's *Initial Decision*.

- ***Base ROE Complaint IV (EL16-64)***. The fourth and final ROE proceeding[27] also went to hearing before an ALJ, Judge Glazer, who issued his initial decision on March 27, 2017.[28] 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.[29] 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*.

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[22] *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*").

[23] *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).

[24] 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%.

[25] 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.

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

[27] 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.

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

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

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.[30] 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.[31]

At highest level, the new methodology will determine whether (1) an existing ROE is unjust and unreasonable under the first prong of FPA section 206 and (2) if so, what the replacement ROE should be under the second prong of FPA section 206. In determining whether an existing ROE is unjust and under the first prong of Section 206, the FERC stated that it will determine a "composite" zone of reasonableness based on the results of three models: the Discounted Cash Flow ("DCF"), Capital Asset Pricing Model ("CAPM"), and Expected Earnings models. Within that composite zone, a smaller, "presumptively reasonable" zone will be established. Absent additional evidence to the contrary, if the utility's existing ROE falls within the presumptively reasonable zone, it is not unjust and unreasonable. Changes in capital market conditions since the existing ROE was established may be considered in assessing whether the ROE is unjust and unreasonable.

If the FERC finds an existing ROE unjust and unreasonable, it will then determine the new just and reasonable ROE using an averaging process. For a diverse group of average risk utilities, FERC will average four values: the midpoints of the DCF, CAPM and Expected Earnings models, and the results of the Risk Premium model. For a single utility of average risk, the FERC will average the medians rather than the midpoints. The FERC said that it would continue to use the same proxy group criteria it established in *Opinion 531* to run the ROE models, but it made a significant change to the manner in which it will apply the high-end outlier test.

The FERC provided preliminary analysis of how it would apply the proposed methodology in the Base ROE I Complaint, suggesting that it would affirm its holding that an 11.14% Base ROE is unjust and unreasonable. The FERC suggested that it would adopt a 10.41% Base ROE and cap any preexisting incentive-based total ROE at 13.08%.[32] 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[33] 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

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[30] *Coakley v. Bangor Hydro-Elec. Co.*, 165 FERC ¶ 61,030 (Oct. 18, 2018) ("*Order Directing Briefs"* or "*Coakley*").

[31] *Id.* at 19.

[32] *Id.* at P 59.

[33] For purposes of the motion seeking clarification, "Customers" are CT PURA, MA AG and EMCOS.

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.

TOs Request to Re-Open Record and file Supplemental Paper Hearing Brief. On December 26, 2019, the TOs filed a Supplemental Brief that addresses the consequences of the November 21 *MISO ROE Order*[34] and requested that the FERC re-open the record to permit that additional testimony on the impacts of the *MISO ROE Order*'s changes. On January 21, EMCOS and CAPs opposed the TOs' request and brief.

These matters are pending before the FERC. If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Joe Fagan (202-218-3901; jfagan@daypitney.com).

II.Rate, ICR, FCA, Cost Recovery Filings

- **Attachment F Modification: Inclusion of UI's Pequonnock Substation Project CWIP (ER20-499)**

On January 28, 2020, the FERC accepted UI's changes to the Attachment F revenue requirement calculation in the ISO-NE OATT.[35] UI's changes include 100% of the construction work in progress ("CWIP") associated with the Pequonnock Substation Project[36] as a line item in the revenue requirement recovered through the Attachment F Implementation Rule.[37] The changes do not modify the formula rate itself.[38] The CWIP changes were accepted effective January 31, 2020, as requested. Unless the January 28 order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **FCA14 Qualification Informational Filing (ER20-308)**

ISO-NE submitted its informational filing (the "FCA14 Informational Filing") for qualification in FCA14 on November 5, 2019, as required under Market Rule Section 13.8.1. The Informational Filing contained ISO-NE's determinations that four Capacity Zones will be modelled for FCA14 -- Southeastern New England ("SENE"), Northern New England ("NNE"), the Maine Capacity Zone ("Maine"), and Rest of Pool. SENE will again be modeled as import-constrained; NNE will be modeled as export-constrained. The Maine Load Zone will be modeled as a separate nested export-constrained Capacity Zone within NNE. The Informational Filing reported that, with Mystic 8 & 9 operating, there will be 34,905 MW of existing capacity in FCA14 competing with 7,314 MW of new capacity under a Net ICR of 32,490 MW (ICR minus HQICCs). ISO-NE reported also that there were a total of 913 MW of Static De-List Bids. A summary of the De-List Bids accepted and those rejected for reliability purposes was included in a privileged Attachment E. ISO-NE qualified 14 demand bids, totaling 446 MW, and 344 supply offers, totaling 749 MW, to participate in the substitution auction.

Comments on the FCA14 Informational Filing were due November 20, 2019. Comments and protests were filed by the ISO-NE External Market Monitor ("EMM"), RENEW Northeast, Inc. ("RENEW") and Able Grid

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[34] *Ass'n of Buss. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569, 169 FERC ¶ 61,129 (2019) ("*MISO ROE Order*").

[35] *The United Illuminating Co.*, Docket No. ER20-499 (Jan. 28, 2020) (unpublished letter order).

[36] 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.

[37] The FERC granted on May 14, 2019, two of the three transmission rate incentives requested by UI in connection with its Pequonnock Substation Project, including the CWIP Incentive. *United Illuminating Co.*, 167 FERC ¶ 61,126 (May 14, 2019).

[38] UI provided notice of these changes by e-mail to the Participants and Transmission Committee on Nov. 1, 2019.

Infrastructure Holding, LLC ("Able Grid"). In its comments, the ***EMM*** discussed the quality and appropriateness of key elements of the IMM's review and mitigation of New Resource Offer Floor Prices ("OFPs") for certain resources in FCA14. The EMM identified methodological concerns with certain elements of the IMM's determinations for large-scale energy storage resources ("ESRs"), suggesting that, while it was appropriate for the IMM to adjust net revenues for Energy and Ancillary Services ("EAS") and mitigate the OFPs of such ESRs, its analyses indicated that the EAS revenue levels assumed by the IMM in mitigating the OFPs were unreasonably low. The EMM asked the FERC to require the IMM to revise its determinations for ESR OFPs for FCA14. ***RENEW*** supported the EMM's comments, and requested that the FERC direct the IMM to re-calculate OFPs for ESRs using the EMM's assumptions and re-issue Qualification Determination Notifications ("QDNs") to all affected ESR developers, with revised OFPs for use in FCA14. ***Able Grid*** requested that the FERC (i) find that, with respect to the four battery storage projects it proposed for qualification, the IMM-determined OFP was calculated in an arbitrary and capricious manner, would result in unjust and unreasonable rates, and (ii) allow Able Grid to participate in FCA14 with its Requested OFP. Doc-less interventions were filed by NEPOOL, Avangrid, Calpine, Dominion (out-of-time), Enerwise Global Technologies ("CPower"), Exelon, Eversource, National Grid, NESCOE, NRG, and Vistra[39] (out-of-time).

On December 5, ***the IMM*** answered the comments and protests of the EMM, RENEW, and Able Grid, asserting that its determinations were "a just and reasonable exercise of buyer-side mitigation in the face of unreasonable, unsupported and/or overly optimistic assumptions underlying requested OCPs by Project Sponsors for ESRs, which otherwise could artificially suppress capacity prices if unchecked". The IMM agreed with RENEW "that there is no perfect revenue model" and "favors more open discussion with market participants in anticipation of future auctions" but asserted that its "estimates are reasonable based on a revenue model that was developed with the benefit of reviewing many submitted models , review for quality assurance, and applied in the mitigation process within the qualification period provided." ***Able Grid*** on December 20 answered the IMM Answer suggesting that the IMM Answer (1) failed to fully address the issues raised in its November 20 Protest; (2) mischaracterized information submitted by Able Grid, resulting in factually incorrect statements; and (3) diverts the FERC's attention from the relevant and relatively limited Tariff provisions that establish the standard for and defines the data categories subject to the IMM's authority under the Tariff to substitute its data for a Project Sponsor.

While this matter is still pending before the FERC, FCA14 has now been run, and was run without an order on this filing. Pursuant to Section III.13.8.1(d) of the Tariff, when the FERC did not issue an order within 75 days after the date of the filing (January 19, 2020) directing otherwise, ISO-NE was authorized to use the determinations contained in the Informational Filing in conducting FCA14. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

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

As previously reported, on December 20, 2018, in a 2-1 decision (Commissioner Glick dissenting; Commissioner McIntyre not voting; Commissioner McNamee not participating), which followed an evidentiary proceeding and two rounds of briefing, the FERC conditionally accepted the Cost-of-Service Agreement ("COS Agreement")[40] among Constellation Mystic Power ("Mystic"), Exelon Generation Company ("ExGen") and ISO-

[39] For purposes of this Report, "Vistra" includes each of Vistra's Related Persons that are NEPOOL Participants: Dynegy Marketing and Trade, LLC; Ambit Northeast LLC; Connecticut Gas & Electric, Inc.; Energy Rewards, LLC; Everyday Energy, LLC; Massachusetts Gas and Electric, Inc.; Public Power, LLC; and Viridian Energy, LLC.

[40] 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.

NE.[41] 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.[42] 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, 2019, 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, 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 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, 2019, 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.[43] The *Mystic*

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[41] *Constellation Mystic Power, LLC*, 165 FERC ¶ 61,267 (Dec. 20, 2018) ("*Mystic Order*").

[42] *Id.* at PP 31-34.

[43] *Constellation Mystic Power,* 164 FERC ¶ 61,022 (July 13, 2018) ("*July Mystic COS Agreement Order*"), *reh'g requested*.

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. This matter remains pending before the FERC. 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[44] (the "2018 Challenge") to Emera Maine's May 15, 2018 annual informational filing[45]and set the remaining issues for hearing and settlement judge procedures.[46] As previously reported, the 2018 Challenge sought certain cost reductions/ exclusions[47] to be effective June 1, 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 accumulated deferred income tax ("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

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[44] 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.

[45] 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.

[46] *Emera Maine*, 167 FERC ¶ 61,090 (Apr. 30, 2019) ("*2018 Challenge Order*").

[47] 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 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.

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 has held two settlement conferences, one on July 18, 2019 and the second on September 11, 2019. A third settlement conference occurred on October 7 and the parties reached an agreement in principle at that time. Since the last Report, on January 23, 2020, Judge Dring issued a report advising that the "participants currently are in the process of finalizing an offer of settlement" and recommending the continuation of settlement judge procedures.

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

- **TOs' *Opinion 531-A* Compliance Filing Undo (ER15-414)**

Rehearing remains pending of the FERC's October 6, 2017 order rejecting the TOs' June 5, 2017 filing in this proceeding.[48] 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*[49] 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.[50] The FERC explained that it will "order such refunds or surcharges as necessary to replace the rates set in the now-vacated order with the rates that the Commission ultimately determines to be just and reasonable in its order on remand" so as to "put the parties in the position that they would have been in but for [its] error." For the time being, so as not to "significantly complicate the process of putting into effect whatever ROEs the Commission establishes on remand" or create "unnecessary and detrimental variability in rates," the FERC has temporarily left in place the ROEs set in *Opinion 531-A*, pending an order on remand.[51] 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

- **ISO-NE eTariff Versioning True-Up (ER20-763)**

On January 9, 2020, ISO-NE filed corrections to remove from the version of § III.13.2 accepted with the PRD Clean-Up Changes (ER20-140) changes submitted with still-pending Fuel Security Retention Limit Revisions (*see* ER20-89 below). Comments on this filing were due on or before January 30; none were filed. NEPOOL submitted a doc-less intervention. 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).

- **ISO-NE Waiver Request: FCA15 De-List Bids Submission Deadline (ER20-759)**

On January 8, 2020, ISO-NE requested waiver of § III.13.1.10(b) of the Tariff to allow Market Participants to adjust or withdraw their FCA15 Retirement De-List Bids or Permanent De-List Bids should ISO-NE make a subsequent non-clerical change to certain ISO Tariff revisions after the current March 13, 2020 deadline for De-List Bids (which will not change) or in the lead-up to (or as part of) the Participants Committee vote on the Energy

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

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

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

[51] *Id.* at P 36.

Security Improvements ("ESI")-related Market Rules (scheduled for April 2, 2020). Under such circumstances, Participants that have submitted an FCA15 Retirement De-List Bid or Permanent De-List Bid would have the option to either (i) update its De-List Bid to reflect the impact of the changes to the ESI design or (ii) withdraw the De-List Bid altogether, and to exercise that option within a week (seven calendar days) following the Participants Committee vote. Comments on ISO-NE's waiver request were due on or before January 29; none were filed. Doc-less interventions were filed by NEPOOL, Dominion, Eversource, Exelon, National Grid, NESCOE, NRG, and Calpine (out-of-time). 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 Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **Fuel Security Retention Sunset (ER20-645)**

On December 19, 2019, ISO-NE and NEPOOL jointly filed changes to sunset one year early the mechanism in the Forward Capacity Market ("FCM") to retain a resource for fuel security reasons ("Fuel Security Retention Sunset"). The fuel security retention mechanism is being sunsetted for the third and final year for which it is to be in place in light of the market solution to be filed in April 2020 and implemented by June 2024. The Sunset was filed so that it can be in effect for the start of the March 2020 FCA15 qualification period, when the fuel security retention review is scheduled to be performed. The Fuel Security Retention Sunset was supported by the Participants Committee at its December 6 meeting (Consent Agenda Item #2). Comments on this filing were due on or before January 9, 2020. On January 9, Exelon protested the filing, stating that "there is simply no reason to shorten the life of the Fuel Security Provisions now when doing so would unnecessarily limit ISO-NE's options for addressing fuel security needs when it is not clear that market reforms will be in place in time for FCA15". Both ISO-NE and NEPOOL answered Exelon's protest, urging the FERC to accept the Fuel Security Retention Sunset as filed. Calpine, Dominion, Eversource, FirstLight, MMWEC, National Grid, NESCOE, NHEC, and NRG filed doc-less interventions only. 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 Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **Waiver Request: FCA14 Qualification (CPower) (ER20-458)**

Still pending, notwithstanding the fact that FCA14 has been run, is the request by Enerwise Global Technologies, Inc. d/b/a/ CPower ("CPower") for a waiver of the FCM qualification rules to allow seven residential and commercial, summer-only solar Distributed Generation On-Peak Demand Resources (the "Resources"), unable to use composite offers for FCA14 participation due to the interplay between RTR proration and substitution auction rules, to participate in FCA14 and the substitution auction. Alternatively, CPower requested, should its primary waiver request not be granted, the waivers necessary to allow the Resources to form a composite offer (if winter capacity remains available); offer into FCA14 at their IMM-mitigated Offer Floor Prices ("OFPs"), and participate in the substitution auction. Comments on CPower's waiver request were due on or before December 9, 2019.

ISO-NE opposed the primary relief requested by CPower (to allow its Solar Demand Resources to participate in FCA14 with only summer Qualified Capacity) but not CPower's request for alternative relief (to allow CPower to undo the RTR election for its Solar Demand Resources and enter into composite offers). On December 12, CPower answered ISO-NE's opposition. Doc-less interventions were filed by NEPOOL, Calpine (out-of-time), National Grid, NRG (out-of-time), and RENEW. Although FCA14 has now been completed, this matter remains pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Waiver Request: FCA14 Qualification (Genbright II) (ER20-366)**

On February 3, 2020, the FERC denied Genbright's request for a waiver of the FCM qualification rules for 14 distributed energy resource projects (the "DER Projects") disqualified from FCA14 based on an ISO-NE finding that the DER Projects' interconnection requests should have been filed with ISO-NE in accordance with Schedule

23 of the OATT prior to the close of the FCA14 Show-of-Interest ("SOI") submission window.[52] As previously reported, Genbright challenged that finding and the equity of the outcome even if the finding were correct (given Eversource's failure to timely and accurately inform each Project of the correct jurisdictional status of the distribution feeder into which the Project would interconnect, as Eversource was required to do). In denying the request, the FERC found that Genbright failed to demonstrate that the waiver request was limited in scope.[53] Unless the February 3 order is challenged, with any challenges due on or before March 4, 2020, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Fuel Security Retention Limit Revision (ER20-89)**

On October 11, ISO-NE and NEPOOL jointly filed a revision to Market Rule 1 Section III.13.2.5.2.5A(j) to make clear that a resource retained for fuel security reasons will not be retained for a longer period for some other reason beyond the two-year fuel-security retention period ("Fuel Security Retention Limit Revision"). The Fuel Security Retention Limit Revision was supported by the Participants Committee at its October 4 meeting (Consent Agenda Item #1). Comments on this filing were due on or before November 1, 2019. ***Exelon protested*** the Revision, asserting that the Revision (i) unduly discriminates against fuel security resources in general, and Mystic specifically; (ii) is premature and unreasonably ignores the likelihood that neither the transmission upgrades nor the comprehensive fuel security market mechanism will be completed or implemented prior to the proposed sunset; and (ii) has not been shown to be just and reasonable. ***NEPGA supported*** the Revision, asking that it be accepted without modification. On November 18, both NEPOOL and ISO-NE answered Exelon's protest. Exelon answered the NEPOOL and ISO-NE answers on November 27. Doc-less interventions were filed by Brookfield, Calpine, Dominion, Eversource, Exelon, LS Power Companies, MMWEC, National Grid, NESCOE, NRG, Verso, and Vistra.

Deficiency Letter. On December 6, the FERC issued a deficiency letter, directing ISO-NE to provide the following additional information: (i) how the Fuel Security Retention Limit Revisions impacts the planning and consideration of outcomes of the Boston Area Needs Assessment and to describe, absent the Revisions, how resources retained for fuel security reasons currently impact the planning of the Boston Area Needs Assessment; and (ii) to explain the actions that ISO-NE would take to mitigate any violations of local reliability criteria if a competitively developed transmission solution cannot be developed or made available in time to alleviate the reliability need that could otherwise be resolved by a resource previously retained for fuel security. The additional information was due and was filed by ISO-NE on January 6, 2020. The submission of the additional information re-set the deadline for FERC action (which is now required on or before March 6, 2020).

Comments on the deficiency letter responses were due January 27, 2020. ***Exelon*** filed the lone set of comments, asserting that ISO-NE's deficiency letter response "does nothing to ameliorate the concerns raised by Exelon and fails to provide additional support to demonstrate that the proposal is just and reasonable and not unduly discriminatory" and renewing its request that the FERC "reject the Fuel Security Retention [Limit] Revision in its entirety."

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 Rosendo Garza (860-275-0660; rgarza@daypitney.com).

[52] *Genbright LLC*, 170 FERC ¶ 61,079 (Feb. 3, 2020).

[53] Id. at PP 29-30 (distinguishing the Genbright request from others previously granted because it sought the waiver of several Tariff provisions, including some that might have allowed the DER Projects to avoid system impact study and other aspects of ISO-NE's "complex interconnection study process").

- **Waiver Request: Vineyard Wind FCA13 Participation (ER19-570)**

Still pending is 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 an RTR. 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. Despite several last minute requests to do so, including a Vineyard Wind 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. 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 November 22, 2019, the FERC conditionally accepted, subject to a 60-day compliance filing, New England's *Order 841*[54] compliance filing.[55] For the majority of the revisions, the effective date was December 3, 2019; the effective date for the revisions to Section II.21, Schedule 9 (Regional Network Service), and Schedule 21 (Local Service) of the OATT was December 1, 2019; the effective date for the remainder of the changes will be January 1, 2024.

In accepting the compliance filing, the FERC directed a number of changes to be submitted in a compliance filing. That compliance filing, which is now due February 10, 2020, must include, among other things:

♦ Modifications to the proposed electric storage resource participation model to account for Maximum Run Time, Maximum Charge Time, State of Charge, Maximum State of Charge, and Minimum State of Charge through bidding parameters or other means in the Day-Ahead Energy Market.

♦ Application of transmission charges to an electric storage resource when that resource is charging for later resale in wholesale markets and is not providing a service. The FERC found that New England's *Order 841* compliance filing did not meet *Order 841* requirements because it proposed to exempt all electric storage resources that are charging for later resale from transmission charges that are applicable to other load. "We reiterate that to the extent that ISO-NE seeks to create a new service that constitutes charging pursuant to economic dispatch under certain

[54] *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*").

[55] *ISO New England Inc.*, 169 FEC ¶ 61,140 (Nov. 22, 2019) ("*Order 841 Initial Compliance Filing Order*").

system conditions, ISO-NE may propose such revisions to its Tariff through a separate FPA section 205 filing."[56]

- Metering and accounting practices for electric storage resources. "We find that ISO-NE's proposal partially complies … the ISO-NE Tariff should include a basic description of ISO-NE's proposed metering methodology and accounting practices for electric storage resources as well as references to specific documents containing further details… [helpful explanation of when language must be "filed"] … The unique physical and operational characteristics of electric storage resources require unique metering and accounting practices to ensure that these resources are charged the LMP for charging energy and are not double charged, as required by Order No. 841. We find that these practices significantly affect rates, terms, and conditions and should be included in the Tariff."[57]

- Tariff revisions that explicitly state that ISO-NE will not charge distribution-connected electric storage resources for charging energy if the distribution utility is unwilling or unable to net out any energy purchases associated with an electric storage resource's wholesale charging activities from the host customer's retail bill. "We find that ISO-NE's Compliance Filing and Tariff provide insufficient detail to demonstrate that electric storage resources will not pay both the wholesale and retail price for the same charging energy."[58]

- An explanation of how the ISO-NE Tariff "allows for electric storage resources to participate in both wholesale and retail markets, or alternatively, revise its Tariff to allow electric storage resources that provide retail services to also participate in ISO-NE's markets, as required by Order No. 841."[59]

The FERC highlighted its expectation that ISO-NE will carry out its commitment to accelerate the development of the capability for Binary Storage Facilities Dispatchable Asset Related Demands ("DARD") to provide regulation service if a stakeholder or developer requests to participate as a Binary Storage Facility and regulate as a DARD.

Extension of compliance filing deadline (now Feb 10, 2020). On December 19, NEPOOL, supported by ISO-NE, moved for a 20-day extension of time, to February 10, 2020, for ISO-NE's submission in response to the *Order 841 Initial Compliance Filing Order*. The extension was intended to facilitate meaningful stakeholder consideration of proposed Tariff revisions before their submission. The FERC granted that extension on December 30, 2019. The compliance filing must now be submitted on or before February 10, 2020, and will be considered during the Participants Committee's February 6 teleconference meeting (Agenda Item #5).

Request for rehearing. On December 23, 2019[60] ISO-NE requested rehearing of the FERC's finding that the initial compliance filing did not comply with *Order 841*'s requirement to allow electric storage resources to account for their state of charge and duration in the Day-Ahead Energy Market. ISO-NE asserted that the finding "ignore[d] substantial record evidence and would require ISO-NE to implement a needlessly

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[56] *Id.* at P 20.

[57] *Id.* at P 220.

[58] *Id.* at P 221.

[59] *Id.* at P 224.

[60] The Request for Rehearing was assigned a Dec. 26 filing date in FERC's eLibrary as filing was successfully completed shortly after the 5pm deadline for official receipt as of the 23rd in the FERC's eFiling system. On December 26, ISO-NE filed a motion explaining the technical difficulties experienced and asked that its request for rehearing be deemed timely filed.

problematic solution. On January 21, 2020, the FERC issued a tolling order affording it additional time to consider ISO-NE's request for rehearing, which remains pending 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*[61] remain pending before the FERC. As previously reported, the *Fuel Security Retention Proposal Order* accepted ISO-NE's Proposal[62] 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.[63] 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, 2018 order,[64] 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."[65] 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

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[61] *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.

[62] As previously reported, ISO-NE filed, in response to the *Mystic Waiver Order*, "interim Tariff revisions that provide for the filing of a short-term, cost-of-service agreement to address demonstrated fuel security concerns". ISO-NE proposed three sets of provisions to expand its authority on a short-term basis to enter into out-of-market arrangements in order to provide greater assurance of fuel security during winter months in New England (collectively, the "Fuel Security Retention Proposal"). ISO-NE stated that the interim provisions would sunset after FCA15, with a longer-term market solution to be filed by July 1, 2019, as directed in the *Mystic Waiver Order*. In addition, the ISO-NE transmittal letter described (i) the generally-applicable fuel security reliability review standard that will be used to determine whether a retiring generating resource is needed for fuel security reliability reasons; (ii) the proposed cost allocation methodology (Real-Time Load Obligation, though ISO-NE indicated an ability to implement NEPOOL's alternative allocation methodology if determined appropriate by the FERC); and (iii) the proposed treatment in the FCA of a retiring generator needed for fuel security reasons that elects to remain in service. The ISO-NE Fuel Security Changes were considered but not supported by the Participants Committee at its August 24, 2018 meeting. There was, however, super-majority support for (1) the Appendix L Proposal with some important adjustments to make that proposal more responsive to the FERC's guidance in the Mystic Waiver Order and other FERC precedent, and (2) the PP-10 Revisions, also with important adjustments (together, the "NEPOOL Alternative").

[63] "PIOs" for purposes of this proceeding are Sierra Club, NRDC, Sustainable FERC Project, and Acadia Center.

[64] *ISO New England Inc. and New England Power Pool Participants Comm.*, 165 FERC ¶ 61,088 (Nov. 9, 2018) ("*Economic Life Determination Revisions Order*").

[65] *Economic Life Determination Revisions Order* at P 23.

ratemaking."[66] 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."[67] 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[68] that (i) denied ISO-NE's request for waiver of certain Tariff provisions that would have permitted ISO-NE to retain Mystic 8 & 9 for fuel security purposes (ER18-1509); and (ii) instituted an FPA Section 206 proceeding (EL18-182) (having preliminarily found that the ISO-NE Tariff may be unjust and unreasonable in that it fails to address specific regional fuel security concerns identified in the record that could result in reliability violations as soon as year 2022). The *Mystic Waiver Order* required ISO-NE, on or before August 31, 2018 to either: (a) submit interim Tariff revisions that provide for the filing of a short-term, cost-of-service agreement (COS Agreement) to address demonstrated fuel security concerns (and to submit by July 1, 2019 permanent Tariff revisions reflecting improvements to its market design to better address regional fuel security concerns "Chapter 3 Proposal"); or (b) show cause as to why the Tariff remains just and reasonable in the short- and long-term such that one or both of Tariff revisions filings is not necessary.

Addressing the waiver element, the FERC found the waiver request "an inappropriate vehicle for allowing Mystic 8 and 9 to submit a [COS Agreement] in response to the identified fuel security need" and further that the request "would not only suspend tariff provisions but also alter the existing conditions upon which a market participant could enter into a [COS Agreement] (for a transmission constraint that impacts reliability) and allow for an entirely new basis (for fuel security concerns that impact reliability) to enter into such an agreement." The FERC concluded that "[s]uch new processes may not be effectuated by a waiver of the ISO-NE Tariff; they must be filed as proposed tariff provisions under FPA section 205(d)."[69] 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."[70]

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).[71] 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.[72] The FERC also directed ISO-NE include with any proposed Tariff revisions a mechanism that

[66] *Id.* at P 24.

[67] *Id.* at P 27.

[68] *ISO New England Inc.*, 164 FERC ¶ 61,003 (July 2, 2018), *reh'g requested* ("*Mystic Waiver Order*").

[69] *Id.* at P 47.

[70] *Id.* at P 48.

[71] *Id.* at P 55.

[72] *Id.* at PP 56-57.

addresses how cost-of-service-retained resources would be treated in the FCM[73] and an *ex ante* cost allocation proposal that appropriately identifies beneficiaries and adheres to FERC cost causation precedent.[74]

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***[75] (requesting that the FERC clarify that (i) the discussion in the *Mystic Waiver Order* of pricing treatment in the FCM for fuel security reliability resources is not a final determination nor is it intended to establish FERC policy; (ii) the FERC did not intend to prejudge whether entering those resources in the FCM as price takers would be just and reasonable; and (iii) that ISO-NE may confirm its submitted position that price taking treatment for these resources would, in fact, be a just and reasonable outcome. Failing such clarification, Connecticut Parties request rehearing, asserting that the record fails to support a determination that resources retained for reliability to address fuel security concerns must be entered into the FCM at a price greater than zero);
- ***ENECOS*** (asserting that the *Mystic Waiver Order* (i) misplaces reliance on ISO-NE "assertions concerning 'fuel security,' which do not in fact establish a basis in evidence or logic for initiating" a Section 206(a) proceeding; (ii) impermissibly relies on extra-record material that the FERC did not actually review and that intervenors were afforded no meaningful opportunity to challenge; and (iii) speculation concerning potential future modifications to the FCM bidding rules as to retiring generation retained for fuel security misunderstands the problem it seeks to address, and prejudices the already truncated opportunities for stakeholder input in this proceeding), ENECOS suggest that the FERC should grant rehearing, vacate its show cause directive, strike its dictum concerning potential treatment of FCM bidding for retiring generation retained for "fuel security," and direct ISO-NE to proceed either in accordance with its Tariff or under FPA Section 205 to address, with appropriate evidentiary support, whatever concerns it believes to exist concerning "fuel security");
- ***MA AG*** (asserting that the decision to institute a Section 206 proceeding was insufficiently supported by sole reliance on highly contested OFSA and Mystic Retirement Studies; and the FERC should reconsider the timeline for the permanent tariff solution and set the deadline for implementation no later than February 2020);
- ***MPUC*** (challenging the Order's (i) adoption of ISO-NE's methodology and assumptions in the OFSA and Mystic Retirement Studies without undertaking any independent analysis; (ii) failure to address arguments and analysis challenging assumptions in the OFSA and Mystic Retirement Studies; (iii) failure to address the MPUC argument that the Mystic Retirement Studies adopted a completely new standard for determining a reliability problem three years in advance; (iv) unreasonably discounting of the ability of Pay-for-Performance to provide sufficient incentives to Market Participants to ensure their performance under stressed system conditions; and (v) failure to direct ISO-NE to undertake a Transmission Security Analysis consistent with the provisions in the Tariff);
- ***New England EDCs***[76] (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

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[73] *Id.* at P 57.

[74] *Id.* at P 58.

[75] "Connecticut Parties" are the Conn. Pub. Utils. Regulatory Authority ("CT PURA") and the Conn. Dept. of Energy and Environ. Protection ("CT DEEP").

[76] 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).

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***[77] (asserting that (i) the FERC failed to respond to or provide a reasoned explanation for rejecting the arguments submitted by numerous parties that key assumptions underlying and the results of the ISO-NE analyses were flawed; and (ii) the FERC's determination that ISO-NE's analyses were reasonable is not supported by substantial evidence in the record); and
- ***AWEA/NGSA*** (asserting that the FERC erred (i) in finding that ISO-NE's OFSA and subsequent impact analysis of fuel security was reasonable without further examination and (ii) in its preliminary finding that a short-term out-of-market solution to keep Mystic 8 & 9 in operation is needed to address fuel security issues).

On August 13, 2018, CT Parties opposed the NEPGA motion for clarification. On August 14, NEPOOL filed a limited response to Indicated New England EDCs, requesting that the FERC "reject the relief sought in [their motion] to the extent that relief would bypass or predetermine the outcome of the stakeholder process, without prejudice to [them] refiling their proposal, if appropriate, following its full consideration in the stakeholder process." Answers to the Indicated New England EDCs were also filed by the MA AG, NEPGA, NextEra, and CLF/NRDC/Sierra Club/Sustainable FERC Project. On August 29, the Indicated New England EDCs answered the August 14/16 answers. On August 27, 2018, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending.

If you have any questions concerning this proceeding, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **CASPR (ER18-619)**

Rehearing of the FERC's order accepting ISO-NE's Competitive Auctions with Sponsored Policy Resources ("CASPR") revisions,[78] 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***[79] (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***[80] (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).

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[77] "PIOs" are the Sierra Club, Natural Resources Defense Council ("NRDC"), and Sustainable FERC Project.

[78] *ISO New England Inc.*, 162 FERC ¶ 61,205 (Mar. 9, 2018) ("*CASPR Order*"), *reh'g requested*.

[79] 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.

[80] For purposes of this proceeding, "Clean Energy Advocates" are, collectively, the NRDC, Sierra Club, Sustainable FERC Project, CLF, and RENEW Northeast, Inc.

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

On January 24, 2020, the FERC denied rehearing of its October 6, 2017 order[81] accepting updated FCM CONE, Net CONE and ORTP values.[82] In the *CONE/ORTP Updates Order*, 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%), accepting the updated values effective as of March 15, 2017, as requested. On November 6, 2017, NEPGA requested rehearing of the *CONE/ORTP Updates Order*. In denying rehearing, the FERC disagreed with the contentions raised by NEPGA and affirmed its prior determinations. Unless the *CONE/ORTP Updates Rehearing Order* is challenged in Federal Court, the proceeding will be concluded. 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.[83] In the *2013/14 Winter Reliability Program Remand Order*, the FERC directed ISO-NE to request from Program participants the basis for their bids, including the process used to formulate the bids, and to file with the FERC a compilation of that information, an IMM analysis of that information, and ISO-NE's recommendation as to the reasonableness of the bids, so that the FERC can further consider the question of whether the Bid Results were just and reasonable.[84] 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

- **CIP IROL Cost Recovery Rules (ER20-739)**

On January 6, 2020, ISO-NE filed revisions to incorporate into the Tariff as a new Schedule 17 a mechanism to facilitate the recovery of critical infrastructure protection ("CIP") costs by facilities that ISO-NE identifies as critical to the derivation of Interconnection Reliability Operating Limits ("IROL") (the "CIP IROL Cost Recovery Rules"). ISO-NE requested a March 6, 2020 effective date for the CIP IROL Cost Recovery Rules. The CIP IROL Cost

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81 *ISO New England Inc.*, 161 FERC ¶ 61, 035 (Oct. 6, 2017)("*CONE/ORTP Updates Order*"), *reh'g denied* 170 FERC ¶ 61,052 (Jan. 24, 2020).

82 *ISO New England Inc.*, 170 FERC ¶ 61,052 (Jan. 24, 2020) ("*CONE/ORTP Updates Rehearing Order*").

83 *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).

84 *2013/14 Winter Reliability Program Remand Order* at P 17.

Recovery Rules were considered but not supported by the Participants Committee at its November 1, 2019 meeting (Agenda Item #8). Comments on this filing were due on or before January 27, 2020. On January 22, NEPOOL filed comments to provide the FERC with further information explaining NEPOOL's consideration of the Rules and reasons provided by members for supporting or not supporting the Rules. Calpine, Cross-Sound Cable, and the IROL-Critical Facility Owners[85] filed comments supporting the Rules. NESCOE conditionally supported the Rules, subject to the FERC providing its requested guidance and clarifications.[86] Doc-less interventions only were filed by: Brookfield, Dominion, Eversource, Exelon, MA AG, National Grid, NextEra (out-of-time), PSEG, UI, MA DPU, MPUC, Public Citizen, and RESA. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Interconnection Service Capability Changes (ER20-450)**

On January 14, 2020, the FERC accepted revisions that consolidate the rules governing the determination of interconnection service capabilities into a single new section of the OATT and to add to those rules an exception to the formulaic determination of winter interconnection service capabilities in certain instances (the "Changes").[87] The Changes were accepted effective as of January 22, 2020, as requested. Unless the January 14 order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Interconnection Studies Scope and Reasonable Efforts Timelines Changes (ER19-1952)**

Still pending before the FERC are changes to Schedule 22 of the OATT, filed May 22, 2019 by ISO-NE, NEPOOL and the PTO AC, 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 #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).

- **ISO-NE *Order 845* Compliance Filing (ER19-1951)**

Similarly, the proposed revisions to the Large Generator Interconnection Procedures ("LGIP") and Agreement ("LGIA") in Schedule 22 of the ISO-NE OATT jointly filed on May 22, 2019 by ISO-NE and the PTO AC ("Filing Parties") in response to the requirements of *Order 845* ("ISO-NE/TO Proposal") remain pending. The Filing Parties asserted that the ISO-NE/TO Proposal "fully compl[ies] with the requirements in Order Nos. 845

[85] The "IROL-Critical Facility Owners" are: Cogentrix, CSC, FirstLight, NextEra, NRG, and Vistra.

[86] NESCOE requested that the FERC (i) clarify that any order approving Schedule 17 is limited in scope and does not set broad precedent, (ii) confirm that under no circumstances may IROL-critical facilities recover costs subject to recovery under another provision of the Tariff or under any other mechanism; (iii) clarify that costs eligible for recovery under Schedule 17 must be solely and directly related to ISO-NE's designation; and (iv) clarify that only going-forward costs are eligible for recovery under Schedule 17.

[87] *ISO New England Inc. et al.*, Docket No. ER20-450 (Jan. 14, 2020) (unpublished letter order).

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-NE/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 ("NEPOOL Proposal"). The Participants Committee considered but did not support the ISO-NE/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-NE/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).

V.Financial Assurance/Billing Policy Amendments

- **NCFA Rate (ER20-395)**

On January 14, 2020, the FERC accepted without change or condition ISO-NE's revisions to the Financial Assurance Policy ("FAP") that will base the financial assurance calculation for non-commercial capacity ("NCFA"), both before and after a Forward Capacity Auction, on Net CONE rather than on the starting price (before the FCA) and the clearing price (after the FCA) ("NCFA Rate Changes").[88] As previously reported, ISO-NE identified the following three advantages to the Changes: (i) uniform collateral requirements will provide non-commercial resources an incentive to deliver; (ii) uncertainty regarding the amount of collateral that will be required after an FCA is conducted will be reduced; and (iii) the amount of collateral that must be provided by non-commercial resources *prior to* an FCA will be reduced. ISO-NE explained that whether the changes require increased collateral *after* an FCA will depend on whether Net CONE is higher than the FCA clearing price (in which case the changes represent an increase in post-FCA required collateral) or lower than the FCA clearing price (in which case the changes will represent a decrease in post-FCA required collateral). In accepting the NCFA Rate Changes and the

[88] *ISO New England Inc.*, 170 FERC ¶ 61,011 (Jan. 14, 2020) ("*NCFA Rate Order*").

timing of their application, the FERC did not agree with assertions by NEPGA that new non-commercial capacity clearing in FCA14 and future FCAs are similarly situated to existing non-commercial capacity that first cleared before FCA14 or that the application of the revisions only to non-commercial resources that first clear in FCA14 (and not to resources that first cleared prior to FCA 14 and have yet to reach commercial operation) is unduly discriminatory.[89] The NCFA Rate Changes were accepted effective January 15, 2020, as requested. Unless the *NCFA Rate Order* is challenged, with any challenges due on or before February 13, 2020, this proceeding will be concluded. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

VI.Schedule 20/21/22/23 Changes

- **Schedule 22: Notice of Cancellation of First Revised Clear River LGIA (ER20-586)**

On January 16, 2020, the FERC accepted the December 12, 2019 notice of cancellation of the First Revised LGIA[90] by and among ISO-NE, National Grid and Clear River.[91] The LGIA governed the interconnection of Clear River's project in Burrillville, Rhode Island (the "Clear River Project"). The notice of cancellation was accepted effective as of November 25, 2019, as requested. Unless the January 16 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-ES: Berkshire Phase 2 LSA (ER20-585)**

On December 12, 2019, Eversource filed a Local Service Agreement ("LSA") among NSTAR, Berkshire Wind Power Cooperative Corporation ("Berkshire")[92] and ISO-NE. The LSA provides for Firm and Non-Firm Local Point-To-Point Transmission Service for Berkshire's use of NSTAR (West)'s local facilities for "wheeling-out" power associated with Phase 2 to the regional transmission system.[93] An October 1, 2019 effective date was requested. Comments on this filing were due on or before January 2, 2020; none were filed. This matter is pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 20A-EM: Expiration of Talen IRH Rights Assignment (ER20-375)**

On January 15, 2020, the FERC accepted a revised Schedule 20A-EM filed by Emera Maine as a result of the October 31, 2020 expiration of assignment by BHE to Talen of rights over the Phase I/II HVDC-TF.[94] Upon the effective date of these changes (November 1, 2020), Emera Maine will offer open access transmission service over the Phase I/II HVDC-TF up to the full extent of its rights under new Support Agreements, as may be agreed to by the owners of the Phase I/II HVDC-TF, Emera Maine, and other IRHs. Unless the January 15 order is challenged, this proceeding will be concluded. If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Schedule 21-EM: 2018 Annual Update Settlement Agreement (ER15-1434-003)**

On January 8, 2020, the FERC accepted the joint offer of settlement between Emera Maine and the MPUC submitted May 24, 2019 to resolve certain issues raised by the MPUC in response to Emera Maine's

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[89] *Id.* at PP 14-16.

[90] The effective, first revised LGIA was accepted in *ISO New England Inc. and New England Power Co.*, Docket No. ER19-2419-000 (Sep. 10, 2019); the original LGIA was accepted in *ISO New England Inc.*, 162 FERC ¶ 61,058 (Jan. 26, 2018).

[91] *ISO New England Inc.*, Docket No. ER20-586 (Jan. 16, 2020) (unpublished letter order).

[92] Berkshire is a non-profit entity created by 14 Mass. municipal utilities and MMWEC that owns and operates the 15 MW Berkshire Wind Power Project ("Berkshire Wind") located in Lanesboro, MA.

[93] A LSA for Phase 1 was filed and accepted in Docket No. ER19-309. See *ISO New England Inc. and NSTAR Elec. Co.*, Docket No. ER19-309 (Jan 2, 2019) (unpublished letter order).

[94] *ISO New England Inc.*, Docket No. ER20-375 (Jan. 15, 2020) (unpublished letter order).

June 15, 2018 annual charges update (the "Emera 2018 Annual Update Settlement Agreement").[95] Unless the *Emera 2018 Annual Update Settlement Agreement Order* is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-EM: Recovery of Bangor Hydro/Maine Public Service Merger-Related Costs (ER15-1434-001 *et al.*)**

The MPS Merger Cost Recovery Settlement, filed by Emera Maine on May 8, 2018 to resolve all issues pending before the FERC in the consolidated proceedings set for hearing in the *MPS Merger-Related Costs Order,*[96]and certified by Settlement Judge Dring[97] to the Commission,[98] 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 you have any questions concerning these matters, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VII. NEPOOL Agreement/Participants Agreement Amendments

- **132nd Agreement (Press Membership Provisions) (ER18-2208)**

On January 23, the FERC denied rehearing[99] of its *Press Membership Provisions Order*.[100] 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. 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."[101]

95 *ISO New England Inc. and Emera Maine*, 170 FERC ¶ 61,004 (Jan. 8, 2020) ("*Emera 2018 Annual Update Settlement Agreement Order*").

96 *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.

97 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.

98 *Emera Maine and BHE Holdings*, 163 FERC ¶ 63,018 (June 11, 2018).

99 *New England Power Pool Participants Comm.*, 170 FERC ¶ 61,034 (Jan. 23, 2020) ("*Press Membership Provisions Rehearing Order*").

100 *New England Power Pool Participants Comm.*, 166 FERC ¶61,062 (Jan. 29, 2019) ("*Press Membership Provisions Order*"), *reh'g denied,* 170 FERC ¶ 61,034 (Jan. 23, 2020). 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.

101 *Id.* at P 50.

In its request for rehearing and/or clarification, NEPOOL asked the FERC to clarify the extent to which the FERC sought to assert jurisdiction over the NEPOOL Agreement, or in the alternative, grant rehearing on the grounds that the Order reflected an impermissible exercise of the FERC's jurisdiction. The FERC denied rehearing, stating that the *Press Membership Provisions Order* "provided a reasoned explanation of its jurisdiction based directly on the relevant statutory language and its application to the facts presented." The FERC went on to state that "FPA section 205 applies to 'all rules and regulations affecting or pertaining to' jurisdictional rates, and this designation of scope is broad enough to encompass those aspects of NEPOOL operations that the [FERC] found to be jurisdictional in the [*Press Membership Provisions Order*]" and to dismiss the contention that the *Press Membership Provisions Order* could have implications for matters that do not pertain to qualifications for NEPOOL membership. As noted above, the FERC dismissed in a concurrently issued order the RTO Insider Complaint summarized in EL18-196 above. Unless the *Press Membership Provisions Rehearing Order* is challenged in Federal Court, this proceeding will be concluded. 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*[102] *and 531-B*[103] 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).

- **Transmission Projects Annual Informational Filing (ER13-193)**

On January 30, 2020, ISO-NE filed, as required under Section 4.1(j)(iii) of the OATT, its annual informational filing of projects on the RSP project list that had a year of need three years or less from the completion of the Needs Assessment. The list of prior year designations is maintained on the ISO-NE website at https://www.iso-ne.com/static-assets/documents/2020/01/2019-prior-year-projects-section-4-j-iii-final.pdf. This filing will not be noticed for public comment by the FERC.

- **LFTR Implementation: 45th Quarterly Status Report (ER07-476; RM06-08)**

ISO-NE filed the 45th of its quarterly status reports regarding LFTR implementation on January 15, 2020. ISO-NE reported that it implemented monthly reconfiguration auctions (accepted in ER12-2122)

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

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

beginning with the month of October 2019. ISO-NE further reported that, while it will continue to evaluate its as-filed LFTR design and financial assurance issues, including an ongoing evaluation of the FTR market and risk associated with FTRs and LFTRs, it is currently focused on higher priority market-design initiatives. These status reports are not noticed for public comment.

IX. Membership Filings

- **February 2020 Membership Filing (ER20-923)**

On January 31, 2020 NEPOOL requested that the FERC accept (i) the memberships of Avangrid Networks, Inc. [Provisional Member, Related Person to Avangrid Companies (Transmission Sector)]; TrueLight Commodities, LLC (Supplier Sector); and Weaver Wind, LLC (AR Sector, RG Sub-Sector, Large RG Group Member); (ii) the termination of the Participant status of: BBPC LLC d/b/a Great Eastern Energy (Supplier Sector); Precept Power LLC (Supplier Sector); and the TransCanada Companies (TransCanada Power Marketing Ltd, TCPL Power Ltd.; and TransCanada Energy Ltd.) (Supplier Sector); and (iii) the name change of Mercuria Energy America, LLC (f/k/a Mercuria Energy America, Inc.). Comments on this filing are due on or before February 21.

- **January 2020 Membership Filing (ER20-710)**

On December 30, NEPOOL requested that the FERC accept the memberships of Enel Trading North America, LLC ([Related Person to Enel X Companies (AR Sector, LR Sub-Sector)]); MP2 Energy LLC ([Related Person to Shell and MP2 Energy New England (Supplier Sector)]); and Rodan Energy Solutions (USA) Inc. (Provisional Member Group Seat). This matter is pending before the FERC.

- **December 2019 Membership Filing (ER20-493)**

On January 27, the FERC accepted Dichotomy Collins Hydro LLC's membership (AR Sector, RG Sub-Sector, Small Group Member), effective December 1, 2019.[104] Unless the January 27 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 Regional Reliability Standard: PRC-006-NPCC-2 (RD20-1)**

On December 23, 2019, NERC and NPCC filed for approval proposed changes to Regional Reliability Standard PRC-006-NPCC2 (Automatic Underfrequency Load Shedding ("UFLS")), the associated implementation plan, Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs"), and the retirement of the current version of the regional reliability standard. The purpose of PRC-006-NPCC-2 is to establish more stringent and specific NPCC UFLS program requirements than the NERC continent-wide PRC-006 standard, such that declining frequency is arrested and recovered in accordance with established NPCC performance requirements. NPCC states that it has revised the currently effective PRC-006-NPCC-1 to remove redundancies with PRC-006-3, clarify obligations for registered entities, improve communication of island boundaries to affected registered entities, and provide entities with the flexibility to calculate net load shed for UFLS in certain situations. NPCC asked that PRC-006-NPCC-2 become effective on the first day of the first calendar quarter following approval, with the exception of R.3, which would become effective one year from the effective date. Comments on the proposed changes were due on or before January 22, 2020; none were filed. This matter is pending before the FERC.

[104] *New England Power Pool Participants Comm.*, Docket No. ER20-493 (Jan. 27, 2020) (unpublished letter order).

- **NOPR - Retirement of Reliability Standard Requirements (Standards Efficiency Review) (RM19-17; RM19-16)**

On January 23, 2020, the FERC issued a NOPR[105] proposing to approve the retirement of 74 of the 77 Reliability Standard requirements requested to be retired by NERC in these two dockets[106] in connection with the first phase of work under NERC's Standards Efficiency Review[107] ("*Retirements NOPR*"). The FERC explained in the *Retirements NOPR* that the requirements to be retired "(1) provide little or no reliability benefit; (2) are administrative in nature or relate expressly to commercial or business practices; or (3) are redundant with other Reliability Standards."[108] The FERC also proposes to approve the associated VRFs, VSLs, implementation plan, and effective dates proposed by NERC. With respect to the remaining three requirements that NERC seeks to retire, the FERC seeks more information on two -- the retirement of FCA-008-3, Requirements R7 and R8 (with the FERC's final determination to be based on the comments received) – and proposes to remand one – VAR-001-6 – in order to retain R2, which it found neither redundant nor unnecessary for reliability. Comments on the *Retirements NOPR* are due [60 days after the date of the NOPR's publication in the *Federal Register*].[109]

- ***Order 867*** **- Revised Reliability Standard: TPL-001-5 (RM19-10)**

On January 23, 2020, the FERC approved revised Reliability Standard -- TPL-001-5 (Transmission System Planning Performance Requirements), and its associated implementation plan, VRFs and VSLs (together, the "TPL-001 Changes").[110] As previously reported, the TPL-001 Changes are to 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. The FERC determined *not* to direct NERC, as proposed in the *TPL-001-5 NOPR,*[111] 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. *Order 867* will become effective [60 days after the date of publication in the *Federal Register*]. Unless *Order 867* is challenged, this proceeding will be concluded.

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[105] *Electric Reliability Organization Proposal to Retire Requirements in Rel. Standards Under the NERC Standards Efficiency Review*, 170 FERC ¶ 61,032 (Jan. 23, 2020).

[106] As previously reported, NERC filed in ***RM19-17*** for approval (i) the retirement of individual requirements 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). NERC filed in ***RM19-16*** for approval of the retirement of individual requirements 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).

[107] 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.

[108] *Id.* at P 1.

[109] The *Retirements NOPR* has not yet been published in the *Fed. Reg.*

[110] *Transmission Planning Rel. Standard TPL-001-5*, Order No. 867, 170 FERC ¶ 61,030 (Jan. 23, 2020) ("*Order 867*").

[111] *Transmission Planning Rel. Standard TPL-001-5*, 167 FERC ¶ 61,249 (June 20, 2019) ("*TPL-001-5 NOPR*").

- ***Order 866*** **- New Reliability Standard: CIP-012-1 (RM18-20)**

On January 23, 2020, the FERC approved new Reliability Standard -- CIP-012-1 (Cyber Security – Communications between Control Centers),[112] and associated Glossary definitions, implementation plan, VRFs and VSLs (together, the "Control Center Cyber Security Communication Changes").[113] *Order 866* also directed NERC to 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. In light of the comments received in response to the *CIP-012-1 NOPR*,[114] *Order 866* does not require NERC to clarify the types of data that must be protected.[115] *Order 866* will become effective [60 days after the date of its publication in the *Federal Register*]. Unless *Order 866* is challenged, this proceeding will be concluded.

- **5-Year ERO Performance Assessment Report (RR19-7)**

On January 23, 2020, the FERC accepted NERC's Performance Assessment,[116] finding (i) that NERC "continues to satisfy the statutory and regulatory criteria for certification as the ERO"; (ii) that the Regional Entities continue to satisfy applicable statutory and regulatory criteria; and (iii) that NERC should take several actions to continue improving its performance as the ERO. Specifically, the FERC directed NERC to submit a 90-day compliance filing providing additional information and a second, 180-day compliance filing revising NERC's Rules of Procedure to address specific matters as discussed in the *2020 Five Year Order*.[117] Challenges, if any, to the *2020 Fiver Year Order* are due on or before February 24, 2020.

XI. Misc. - of Regional Interest

- **203 Application: CMP/NECEC (EC20-24)**

On December 10, 2019, CMP requested authorization to transfer to NECEC Transmission LLC 7 TSAs, executed on June 13, 2018, that provide the rates, terms, and conditions under which transmission service will be provided over the New England Clean Energy Connect ("NECEC") Transmission Line to the participants that are funding construction of the Line. Comments on the 203 application were due on or before December 31, 2019; none were filed. Doc-less interventions were filed by Eversource, HQUS and National Grid. On January 8, 2020, CMP supplemented the application to correct an error in the accounting entries attached as Exhibit N to the original application. This matter remains pending before the FERC.

[112] 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.

[113] *Critical Infrastructure Protection Rel. Standard CIP-012-1 – Cyber Security – Communications between Control Centers*, Order No. 866, 170 FERC ¶ 61,031 (Jan. 23, 2020) ("*Order 866*").

[114] *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*").

[115] *Id.* at P 42.

[116] *N. Amer. Elec. Rel. Corp.*, 170 FERC ¶ 61,029 (Jan. 23, 2020) ("*2020 Five Year Order*"). NERC's performance assessment report, filed July 22, 2019, (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 FERC in *N. Amer. Elec. Rel. Corp.*, 149 FERC ¶ 61,141, at P 70 (2014) ("*2014 Five Year Order*")).

[117] *Id.* at P 2.

- **203 Application: Verso/Pixelle (EC20-20)**

On January 17, the FERC authorized the sale of 100% of the indirect membership interests in Verso Energy Services and Verso Androscoggin to Pixelle Specialty Solutions LLC ("Pixelle").[118] Pursuant to the January 17 order, notice must be filed within 10 days of consummation of the sale, which as of the date of this Report has not yet occurred. The change in upstream ownership will not impact Verso's membership in the Generation Sector.

- **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.[119] Pursuant to the June 25 order, notice must be filed within 10 days of consummation of the transaction, which as of the date of this Report has not yet occurred.

- **PJM MOPR-Related Proceedings (EL18-178; EL16-49)**

On December 19, 2019, in a long-awaited order (approved 2-1),[120] the FERC ***found*** that "any resource, new *or existing*, that receives, or is entitled to receive, a State Subsidy, and does not qualify for [an exemption], should be subject to the [Minimum Offer Price Rule ("MOPR")]"[121] and ***directed*** PJM to submit a replacement rate that "extends the MOPR to include both new and existing resources, internal and external, that receive, or are entitled to receive, certain out-of-market payments, with certain exemptions."[122] The FERC directed PJM to include five exemptions: (1) a Self-Supply Exemption [PP 12; 202-204]; (2) a Demand Response, Energy Efficiency, and Capacity Storage Resources Exemption [PP 13; 208-209]; (3) a RPS Exemption [PP 14; 173-174]; (4) a Competitive Exemption [PP 15; 161]; and (5) a Unit-Specific Exemption [PP 16; 214-216].[123] The FERC established the replacement rate under section 206 of the FPA, but declined to order refunds (which it otherwise had the discretion to do).[124] The FERC directed PJM to submit a compliance filing consistent with its guidance on or before March 18, 2020 (90 days from the date of the *Dec 2019 PJM MOPR Order*). In the compliance filing, PJM was directed to also provide revised dates and timelines for the 2019 Base Residual Auction ("BRA") and related incremental auctions, along with revised dates and timelines for the May 2020 BRA and related incremental auctions.[125]

The *Dec 2019 PJM MOPR Order* is the latest milestone in the FERC's consideration of out-of-market support affecting the PJM capacity market.[126] As previously reported, the FERC found in a *June 2018 PJM*

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118 *Verso Androscoggin LLC and Verso Energy Services LLC*, 170 FERC ¶ 62,037 (Jan. 17, 2020).

119 *Emera Maine*, 167 FERC ¶ 62,194 (June 25, 2019).

120 *PJM Interconnection, L.L.C.* and *Calpine Corp. et al.*, 169 FERC ¶ 61,239 (Dec. 19, 2019) ("*Dec 2019 PJM MOPR Order*").

121 *Id.* at P 9 (emphasis added).

122 *Id.* at P 2 ("[g]oing forward, the default offer price floor for applicable new resources will be the Net Cost of New Entry ("Net CONE") for their resource class; the default offer price floor for applicable existing resources will be the Net Avoidable Cost Rate ("Net ACR") for their resource class").

123 *Id.* ("The replacement rate will include three categorical exemptions to reflect reliance on prior Commission decisions: (1) existing self-supply resources, (2) existing demand response, energy efficiency, and storage resources, and (3) existing renewable resources participating in RPS programs. The replacement rate will also include a fourth exemption, the Competitive Exemption, for new and existing resources that are not subsidized and thus do not generally require review to protect 'the integrity and effectiveness of the capacity market.' To preserve flexibility, PJM will also permit new and existing suppliers that do not qualify for a categorical exemption to justify a competitive offer below the applicable default offer price floor through a Unit-Specific Exemption.")

124 *Id.* at P 3. The FERC had previously established a refund effective date of March 21, 2016, the date of the original Calpine Complaint in EL16-49.

125 *Id.* at P 4. As previously reported, the FERC directed PJM not to run the BRA in August 2019 as it had proposed to do (*see Calpine et al. v. PJM*, 168 FERC ¶ 61,051 (July 25, 2019)).

126 The *PJM 2019 MOPR Order* addressed a paper hearing that arose from 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,

MOPR Order[127] 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," determined that the PJM Tariff was unjust and unreasonable, rejected the PJM MOPR Filing, granted in part Calpine's Complaint, and *sua sponte* initiated a new FPA section 206 proceeding (EL18-178) in which it conducted a paper hearing to resolve proposed alternatives, whether put forth in the *June 2018 PJM MOPR Order* or otherwise,[128] addressing "price-suppressive" effects of out-of-market support for certain resources.

The *Dec 2019 PJM MOPR Order* affirms the FERC's prior finding that "[a]n expanded MOPR with few or no exceptions, should protect PJM's capacity market from the price-suppressive effects of resources receiving out-of-market support by ensuring that such resources are not able to offer below a competitive price."[129] The expanded MOPR[130] only applies to "State-Subsidized Resources" (Resources that receive, or are entitled to receive, State Subsidies).[131] The FERC considers a "State Subsidy" to be:

> a direct or indirect payment, concession, rebate, subsidy, non-bypassable consumer charge, or other financial benefit that is (1) a result of any action, mandated process, or sponsored process of a state government, a political subdivision or agency of a state, or an electric cooperative formed pursuant to state law, and that (2) is derived from or connected to the procurement of (a) electricity or electric generation capacity sold at wholesale in interstate commerce, or (b) an attribute of the generation process for electricity or electric generation capacity sold at wholesale in interstate commerce, or (3) will support the construction, development, or operation of a new or existing capacity resource, or (4) could have the effect of allowing a resource to clear in any PJM capacity auction.[132]

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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 MOPR Filing"). The PJM MOPR 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"). A summary of the development and FERC consideration of PJM's capacity market is set out in the Order.

[127] *Calpine Corp. et al.*, 163 FERC ¶ 61,236 (June 29, 2018) ("*June 2018 PJM MOPR Order*"), *clarif. and/or reh'g requested*.

[128] The proposed alternative approach would have (i) modified 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, established an option in PJM's Tariff that would allow, on a resource-specific basis, resources receiving out-of-market support to choose to be removed from the PJM capacity market, along with a commensurate amount of load, for some period of time. That option, which is similar in concept to the Fixed Resource Requirement ("FRR") that currently exists in PJM's Tariff, is referred to as the "FRR Alternative." Unlike the existing FRR construct, the FRR Alternative would apply only to resources receiving out-of-market support.

[129] *Dec 2019 PJM MOPR Order* at P 5.

[130] The FERC adopted an expanded MOPR rather than PJM's Resource Carve-Out ("RCO") and Extended RCO proposals. The FERC determined that those proposals would unacceptably distort the markets, inhibiting incentives for competitive investment in the PJM market over the long term. PJM's longstanding FRR Alternative remains unchanged in the PJM tariff. *See Id.* at P 6.

[131] Resources with federal subsidies will not be subject to the MOPR. *See Id.* at P 10.

[132] *Id.* at P 9. Renewable Energy Credits (RECs) procured as part of a state-mandated or state-sponsored procurement process are State Subsidies. *Id.* at P 176. Demand response, energy efficiency, and capacity storage resources that participate in the PJM capacity market are considered to be capacity resources for purposes of this definition. *Id.* at P 9.

The FERC declined to adopt a materiality threshold for the level of State Subsidies or the size of State-Subsidized Resources. State-Subsidized Resources "that intend to offer below the default offer price floor for a given resource type, and do not qualify for [one of the four] categorical exemption[s], must support their offers through a Unit-Specific Exemption."[133] While the FERC acknowledged that the extension of the MOPR may prevent certain existing resources that states have recently chosen to subsidize from clearing PJM's capacity auctions, it noted that states may continue to support their preferred resource types in pursuit of state policy goals and make decisions about preferred generation resources, with "resources that states choose to support, and whose offers may fail to clear the capacity market under the revised MOPR directed in this order, … still … permitted to sell energy and ancillary services in the relevant PJM markets."[134] The *Order*, the FERC highlighted, "addresses the growing impact of State-Subsidized Resources because those subsidies reject the premise of the capacity market and circumvent competitive outcomes."[135]

The *Dec 2019 PJM MOPR Order* was accompanied by a 28-page dissent of Commissioner Glick ("Glick Dissent"), who explained why he believes the Order to be "illegal, illogical, and truly bad public policy."[136] Commissioner Glick further suggested that it "may well be that a mandatory capacity market is no longer a sensible approach to resource adequacy at a time when states are increasingly exercising their authority under the FPA to shape the generation mix. Indeed, the conclusion that I draw from the record in front of us is not that there is an urgent need to mitigate the effects of state public policies, but rather that we should be taking a hard look at whether a mandatory capacity market remains a just and reasonable resource adequacy construct in today's rapidly evolving electricity sector."[137]

Requests for rehearing and/or clarification ("Requests") of the *Dec 2019 PJM MOPR Order* were filed by over 50 parties, including: PJM IMM, AEP/Duke, AES, Buckeye Power, Calpine, Clean Energy Advocates,[138] CPower, Dominion, EDF Renewables, Exelon, FirstEnergy Utility Companies, First Energy Solutions, Hershey Co., J-POWER, Longroad Development, PSEG, Vistra, Allegheny Electric Coop., East Kentucky Power Coop. ("EKPC"), IL Municipal Electric Agency, North Carolina Electric Membership Corp., Old Dominion Elec. Coop., the S. MD Elec. Coop, the Organization of PJM States ("OPSI"), DC PSC, IL ICC, MD PSC, NJ BPU, OH PUC, PA PUC, VA State Corporation Commission, WV PSC, DE Public Advocate, DC AG, IL AG, MD AG, NJ Div. of Rate Counsel/People's Counsel for DC/MD People's Counsel, OH Consumers' Counsel, PJM Consumer Representatives,[139] Advanced Energy Buyers Group, Advanced Energy Economy ("AEE"), APPA/AMP/Public Power Assoc. of NJ, AWEA, ELCON, EPSA and the PJM Power Providers Group, NEI, NRECA/EKPC, and Public Citizen. An answer to PJM IMM's request for clarification was filed by the Talen PJM Companies. The Requests are pending before the FERC, with FERC action required on or before February 18, 2020, the first business day that is 30 days from the date the first Request was filed, or the Requests will be deemed denied

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133 *Id.* ("A threshold based on resource size will not prevent a collection of smaller resources from having a significant cumulative impact on competitive outcomes. In addition, if a State Subsidy is small enough for a capacity resource to perform economically without it, then the State-Subsidized Resource should be able to secure a Unit-Specific Exemption.")

134 *Id.* at P 7.

135 *Id.* at P 17.

136 Glick Dissent at P 1.

137 Id. at P 62.

138 "Clean Energy Advocates" are, for the purposes of this proceeding, Environmental Defense Fund ("EDF"), Natural Resources Defense Council ("NRDC), Sierra Club, Sustainable FERC Project, and Union of Concerned Scientists ("UCS").

139 PJM Consumer Representatives are: PJM Industrial Customer Coalition ("PJMICC"), Illinois Industrial Energy Consumers ("IIEC"), the Electricity Consumers Resource Council, ("ELCON"), Industrial Energy Consumers of America ("IECA"), the Pennsylvania Energy Consumer Alliance ("PECA"), the Industrial Energy Consumers of Pennsylvania ("IECPA"), and the American Forest and Paper Association ("AF&PA").

by operation of law. For further information on this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@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 EL16-49 and EL18-178 (the PJM MOPR-Related Proceedings). 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, 2019. 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).

- **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).

- **Related Facilities Agreement Cancellations: Clear River Energy (ER20-729/730)**

On January 2, both CL&P (ER20-729) and NSTAR (ER20-730) filed a notice of cancellation of their Related Facilities Agreements ("RFA") with Clear River. The RFAs provided the terms and conditions governing activities and cost responsibility associated with required upgrades in connection with Clear River's LGIA with ISO-NE and National Grid. In light of the cancellation of that LGIA (*see* ER20-586 in Section VI above), Clear River provided a written notice of cancellation of each of the RFAs on November 25, 2019. Accordingly, CL&P and NSTAR each requested that the notice of cancellation of its RFA with Clear River be accepted as of the November 25, 2019. Comments on these notices were due on or before January 23, 2020; none were filed. These proceedings are pending before the FERC. If there are questions on these proceedings, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **EMM Contract (ER20-619)**

On February 4, 2020, the FERC accepted the new 3-year contract with Potomac Economics, Ltd.[140] pursuant to which Potomac Economics will to continue as the ISO-NE EMM. In its filing, ISO-NE noted that the new agreement is closely modeled on the existing agreement between Potomac and ISO-NE, including all of the functions laid out for the EMM in Section 9.4.3 of the Participants Agreement. The new EMM contract term will run from January 1, 2020 through December 31, 2022. Unless the February 4 order is challenged, this proceeding will be concluded. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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[140] *ISO New England Inc.*, Docket No. ER20-619 (Feb. 4, 2020).

- **D&E Agreement: CL&P/CPV Towantic (ER20-521)**

On January 22, the FERC accepted the Preliminary Agreement for Design, Engineering and Construction services (the "D&E Agreement") between Connecticut Light & Power ("CL&P") and CPV Towantic LLC ("CPV Towantic").[141] The D&E Agreement sets forth the terms and conditions under which CL&P will undertake preliminary design and engineering activities on the mitigation of violations (including reconductoring a 115kV 1029-2 line from Bunker Hill to Baldwin Tap) that were identified in ISO-NE's studies that preceded the LGIA executed amongst the parties and ISO-NE. The D&E Agreement was accepted for filing effective as of December 5, 2019, as requested. Unless the January 22 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 were due on or before August 5; none were filed. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Mystic COS Agreement Amendment No. 1 (ER19-1164)**

On January 9, 2020, the FERC rejected the amendment filed by Constellation Mystic Power, LLC ("Mystic") to its COS Agreement with ISO-NE ("Amendment").[142] As previously reported, the Amendment would have provided "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". In rejecting the Amendment as unjust and unreasonable, the FERC agreed with protestors that "allowing Mystic 8 and 9 to potentially retire during the second year of the Mystic Agreement's term would pose an unacceptable risk to reliability"[143] and disagreed with "Mystic's contention that the Amendment is necessary for Mystic to manage ongoing uncertainty about certain aspects of the Mystic Agreement."[144] Unless the *Mystic COS Amendment Order* is challenged, with any challenges due on or before February 10, 2020, this proceeding will be concluded. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **FERC Enforcement Action: ExGen Start-Up Fuel Reporting to ISO-NE (IN20-3)**

On January 10, the FERC approved a Stipulation and Consent Agreement with Exelon Generation Company, LLC ("ExGen")[145] that resolved the investigation by FERC's Office of Enforcement ("OE") into erroneous data transmitted to ISO-NE by ExGen regarding the type and quantity of fuel used to start up Mystic 7. OE determined and ExGen admitted that, from December 2014 through August 2016, as a result of an internal spreadsheet error, Mystic 7's supply offers indicated that it exclusively used No. 6 fuel oil (rather than natural gas) to start up, which caused ExGen to be overcompensated by ISO-NE when Mystic 7 was dispatched out-of-merit. OE did not conclude that ExGen purposefully submitted false data to ISO-NE and accepted the ExGen's representation that the errors were inadvertent. Under the Stipulation and Consent Agreement,

[141] *The Conn. Light and Power Co.*, Docket No. ER20-521 (Jan. 22, 2020) (unpublished letter order).

[142] *Constellation Mystic Power, LLC*, 170 FERC ¶ 61,006 (Jan. 23, 2020) ("*Mystic COS Amendment Order*").

[143] *Id.* at P 14.

[144] *Id.* at P 15.

[145] *Exelon Generation Co., LLC*, 170 FERC ¶ 61,008 (Jan. 10, 2020).

ExGen must ***disgorge $101,756*** (plus interest) to ISO-NE, to be allocated by ISO-NE in its discretion for the benefit of ISO-NE customers and upon approval by OE's of ISO-NE's plan for doing so, and ***pay a $32,500 civil penalty*** to the United States Treasury. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **FERC Enforcement Action: Emera ISO-NE Tariff Violations (IN20-2)**

Also on January 10, the FERC approved a Stipulation and Consent Agreement with Emera Energy ("Emera")[146] that resolved OE's investigation into Emera's violations of the ISO-NE Tariff requirement that Fuel Price Adjustment ("FPA") Requests ("FPA Requests") use fuel costs that reflect an arm's length fuel purchase transaction. OE determined that, on 16 occasions, Emera's FPA Requests for Rumford used information from postings by Emera Energy's gas desk (made specifically to provide the necessary documentation to support an FPA request) rather than information from an arm's length transaction. The reporting resulted in NCPC overpayments of $14,120 when Emera Energy increased its ISO-NE reference level by requesting an above-market fuel price adjustment. Under the Stipulation and Consent Agreement, Emera agreed to ***disgorge $14,120*** (plus ***$2,002.19*** in interest) to ISO-NE, to be allocated by ISO-NE in its discretion for the benefit of ISO-NE customers, and ***pay a $5,000 civil penalty*** to the United States Treasury. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@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 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.

- **FERC Enforcement Action: Order Assessing Civil Penalties – Vitol & F. Corteggiano (IN14-4)**

On October 25, 2019, the FERC issued an order[147] finding Vitol Inc. ("Vitol") and its co-head of FTR trading operations, Frederico Corteggiano, 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").[148] The FERC assessed civil penalties of $1,515,738 against Vitol and $1 million against Corteggiano. In addition, the FERC directed Vitol to disgorge unjust profits, plus applicable interest of $1,227,143.

Because Respondents' previously elected the FPA's *de novo* review procedures, which permits a reviewing federal court "to review *de novo* the law and the facts involved" and "jurisdiction to enter a judgment . . . modifying . . . or setting aside [the assessment] in whole or in Part", the *Vitol Penalties Order* is not subject to

[146] *Exelon Generation Co., LLC*, 170 FERC ¶ 61,008 (Jan. 10, 2020).

[147] *Vitol Inc. and Federico Corteggiano*, 169 FERC ¶ 61,070 (Oct. 25, 2019) ("*Vitol Penalties Order*").

[148] 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.

rehearing, and should the penalty remain unpaid for 60 days, the FERC will institute an action in federal district court for an order affirming the penalties assessed against Respondents.

XII. Misc. - Administrative & Rulemaking Proceedings

- **Credit Reforms in Organized Wholesale Markets (AD20-6)**

On December 16, 2019, the Energy Trading Institute[149] requested that the FERC hold a technical conference and conduct a rulemaking to update the requirements adopted in *Order 741*[150] and Section 35.47 of the FERC's regulations addressing credit and risk management in the markets operated by RTO/ISOs. ETI, citing a recent filing by NYISO (which it protested),[151] and stating that several expedited initiatives related to RTO/ISO credit policies are underway, suggested that it would be helpful for the FERC to consolidate any "filings with this proceeding and hold the technical conference ETI is requesting by March 30, 2020 so the ISOs, RTOs and their stakeholders consider those discussions in any initiatives they have underway." ETI suggested in its request that RTO/ISO credit support requirements be standardized, and that the requested technical conference and rulemaking explore various ways to identify and mitigate counterparty risk (including know-you-customer ("KYC") tools and participant suspensions or bans) and enhance risk management infrastructure/processes within the organized markets. While no technical conference has yet been scheduled or public comment date otherwise set, doc-less interventions have been filed by, among others, PJM, the PJM IMM, SPP, CAISO, Tenaska, Avangrid, and Roscommon Analytics. On January 24, the ISO/RTO Council ("IRC"), including ISO-NE, submitted comments and proposed, as an alternative approach to the one suggested by ETI, that the FERC not commence a rulemaking or schedule a technical conference at this time and instead allow individual RTO/ISOs to address their respective credit and risk management issues, permit sufficient time for experience with the evolving rules to be gained, and then consider the best path forward to facilitate a dialogue on best practices and potential points of alignment among the RTO/ISO.

- ***Order 865*: Civil Monetary Penalty Inflation Adjustments (RM20-2)**

On January 2, 2020, the FERC issued *Order 865*[152] to amend its regulations governing the maximum civil monetary penalties assessable for violations of statutes, rules, and orders within FERC's jurisdiction. The FERC is required to update each such civil monetary penalty on an annual basis every January 15.[153] Of particular interest

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[149] In its request, The Energy Trading Institute ("ETI") describes itself generally as "represent[ing] a diverse group of energy market participants, all with substantial interests in wholesale electricity transactions in Commission-jurisdictional markets. ETI members provide important services to a wide variety of wholesale energy market participants. They act as intermediaries between producers and consumers of electric energy that have mismatched quantity, timing, and contract type needs. In addition, they provide liquidity by engaging in energy related commercial transactions with a variety of market entities including, but not limited to, generation owners, project developers, load-serving entities, and investors. ETI members advocate for markets that are open, transparent, competitive and fair - all necessary attributes for markets ultimately to benefit electricity consumers."

[150] *Credit Reforms in Organized Wholesale Elec. Mkts.*, 75 Fed. Reg. 65942 (2010), FERC Stats. & Regs. ¶ 31,317 (2010) ("*Order 741*"); *order on reh'g*, 76 Fed. Reg. 10492 (2011), FERC Stats. & Regs. ¶ 31,320 (2011) ("*Order 741-A*"); *order on reh'g*, 135 FERC ¶ 61,242 (2011) (*"Order 741-B*"); 18 C.F.R. § 35.47.

[151] *See* Proposed Tariff Amendments to Enhance Credit Reporting Requirements and Remedies, *New York Indep. Sys. Operator*, Inc., Docket No. ER20-483 (filed Nov. 26, 2019).

[152] *Civil Monetary Penalty Inflation Adjustments*, Order No. 865, 170 FERC ¶ 61,001 (Jan. 2, 2020) ("*Order 865*").

[153] *See* Federal Civil Penalties Inflation Adjustment Act Improvements Act of 2015, Sec. 701, Pub. L. 114-74, 129 Stat. 584, 599. The FERC made its first adjustment under the Act in July 2016. *See Civil Monetary Penalty Inflation Adjustments*, Order No. 826, 81 FR 43937 (July 6, 2016), FERC Stats. & Regs. ¶ 31,386 (2016). The second adjustment was made January 9, 2017. *Civil Monetary Penalty Inflation Adjustments*, Order No. 834, 158 FERC ¶ 61, 170 (Jan. 9, 2017). The third adjustment as made January 8, 2018. *Civil Monetary Penalty Inflation Adjustments*, Order No. 839, 162 FERC ¶ 61,010 (Jan. 8, 2018). The fourth adjustment was made January 9, 2019. *Civil Monetary Penalty Inflation Adjustments*, Order No. 853, 166 FERC ¶ 61,041 (Jan. 8, 2019). The fifth adjustment was made January 14, 2020. *Civil Monetary Penalty Inflation Adjustments*, Order No. 865, 170 FERC ¶ 61,001 (Jan. 2, 2020).

is the increase in potential civil penalties for market manipulation, which were increased from $1,269,500 to $1,291,894 per violation, per day. *Order 865* became effective January 14, 2020.[154]

- **Joint Staff White Paper on Notices of Penalty for Violations of CIP Standards (AD19-18)**

On August 27, 2019, the FERC published for public comment a White Paper prepared jointly with NERC staff setting out a proposed new format for NERC Notices of Penalty ("NOP") involving violations of CIP Reliability Standards. The FERC explained that the revised format is intended to improve the balance between security and transparency in the filing of NOPs. Specifically, NERC CIP NOP submissions would consist of a proposed public cover letter that discloses the name of the violator, the Reliability Standard(s) violated (but not the Requirement), and the penalty amount. NERC would submit the remainder of the CIP NOP filing containing details on the nature of the violation, mitigation activity, and potential vulnerabilities to cyber systems as a nonpublic attachment, along with a request for the designation of such information as CEII.

Public comment on the proposal was sought with respect to the following: (i) the potential security benefits from the new proposed format; (ii) potential security concerns that could arise from the new format; (iii) any other implementation difficulties or concerns that should be considered; and (iv) whether the proposed format provides sufficient transparency to the public. Other suggested approaches to CIP NOP submissions were welcomed. No changes to the CIP NOP filing format will be made prior to consideration of public comment on the White Paper. Comments were filed by over 80 parties. This matter is pending before the FERC.

- **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)[155] and terminated the DOE NOPR rulemaking proceeding (RM18-1).[156] In terminating the DOE NOPR proceeding, the FERC concluded that the Proposed Rule and comments received did not support FERC action under Section 206 of the FPA, but did suggest the need for further examination by the FERC and market participants of the risks that the bulk power system faces and possible ways to address those risks in the changing electric markets. On February 7, Foundation for Resilient Societies ("FRS") requested rehearing of the January 8 order terminating the DOE NOPR proceeding. The FERC issued a tolling order on March 8, 2018 affording it additional time to consider the FRS request for rehearing, which remains pending.

Grid Resilience Administrative Proceeding (AD18-7). 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.

[154] *Order 865* was published in the *Fed. Reg.* on Jan. 14, 2020 (Vol. 85, No. 9) pp. 2,016-2,018.

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

[156] 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.

ISO-NE Response. In its response, ISO-NE identified fuel security[157] 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"[158] 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.

- **NOPR: QF Rates and Requirements; Implementation Issues under PURPA (RM19-15)**

In an action that could have significant impacts on the development and financing of renewable resources, the FERC, on September 19, 2019, proposed rules to reform its long-standing regulations implementing sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA").[159] Those regulations address the obligation of electric utilities to purchase power produced by "qualifying facilities" or "QFs" at rates that must be "just and reasonable to the electric consumers of the electric utility and in the public interest, and not discriminate against" those QFs.[160]

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[157] 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."

[158] For purposes of these proceedings, "Clean Energy Advocates" are NRDC, Sierra Club and UCS.

[159] 16 U.S.C. § 2601 et seq. (2018). PURPA was enacted to help lessen the dependence on fossil fuels and promote the development of power generation from non-utility power producers.

[160] 16 U.S.C. § 824a–3; PURPA, Sec. 210(a)-(b).

The *QF NOPR* seeks public comment on draft rule changes "to rebalance the benefits and obligations of the [FERC's] PURPA Regulations in light of the changes in circumstances since the PURPA Regulations were promulgated."[161] The *QF NOPR* proposes the following changes that would revise how and when prices for QF power may be established and would reduce the circumstances under which a utility's mandatory purchase obligation would be triggered:

- Provide states the flexibility to establish QF energy rates at the purchasing utility's avoided costs at the time of energy *delivery*, rather than allowing the QFs to elect to *fix* the energy rate for an extended term at the time the utility becomes compelled to purchase the QF's energy.
- Specify that an avoided cost rate for QF energy can be based on *market factors* (including locational market prices, indices, trading hubs, or competitive solicitation processes) or, at the state's discretion, can continue to be set as they are under current PURPA Regulations.
- Reduce in states with a retail choice program an electric utility's obligation to purchase from QFs to the extent that the utility's provider of last resort ("POLR") supply obligation has been reduced by the state's program. If POLR supplies are obtained through solicitations having a specific contract term, the term of any PURPA purchase contract should match the term of the POLR supply contract.
- Decrease from 20 MW to 1 MW the maximum size of QFs that would be entitled to require utilities located in areas with demonstrably competitive markets (RTO/ISOs) to purchase their power. If QF facilities qualify as cogeneration, the 20 MW cap would not change.
- Replace the "one-mile rule" for determining whether generation facilities under common ownership should be considered to be part of a single facility (to be eligible for favorable QF treatment, a small power production facility must be 80 MW or less). Some have argued that the current one-mile rule has been gamed to permit QF certification of projects that if combined would otherwise exceed the 80 MW cap. The impact of this change, if made, would primarily affect projects in non-RTO/ISO markets (e.g., the bilateral markets of the southern and western United States).
- Clarify that a utility's mandatory purchase obligation under PURPA does not arise until the QF can demonstrate commercial viability and financial commitment pursuant to objective and reasonable state-defined criteria.
- Allow for interested stakeholders to protest the self-certification of a QF.

Comments on the proposed rule changes were due on or before December 3, 2019.[162] More than 130 sets of comments were submitted, including comments from Bloom Energy, Borrego Solar, ConEd, Covanta, CT PURA, MA AG, MA DPU, and AEE. Since the last Report, several Congressman have sent comments supporting comments submitted by others. Chairman Chatterjee acknowledged each of the comments received from Congressmen. Late filed comments were submitted by the American Dams, California PUC, TerraForm and the Arizona Corporation Commission. This matter remains pending before the FERC.

- ***Order 864*: Public Util. Trans. ADIT Rate Changes (RM19-5)**

On November 21, 2019, the FERC issued its final rule a NOPR ("*Order 864*")[163] requiring 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"). Specifically, for transmission formula rates, *Order 864* requires public utilities (i) to deduct excess ADIT from or add deficient ADIT to their rate bases and adjust their income tax allowances by amortized excess or deficient ADIT; and (ii) to incorporate a new permanent worksheet into their transmission formula rates that will annually track ADIT

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[161] *Qualifying Facility Rates and Requirements; Implementation Issues Under the Public Utility Regulatory Policies Act of 1978*, Notice of Proposed Rulemaking, 168 FERC ¶ 61,184 (2019) ("*QF NOPR*").

[162] The *QF NOPR* was published in the *Fed. Reg.* on Oct. 4, 2019 (Vol. 84, No. 193) pp. 53,246-53,275.

[163] *Public Util. Trans. Rate Changes to Address Accumulated Deferred Income Taxes*, Order No. 869, 169 FERC ¶ 61,139 (Nov. 21, 2019), *reh'g requested*.

information. The FERC did not adopt its proposals in the ADIT NOPR[164] that were applicable to public utilities with stated rates. *Order 864* will become effective January 27, 2020. Requests for rehearing were filed by APPA and Exelon. On January 21, 2020, the FERC issued a tolling order affording it additional time to consider the APPA and Exelon requests.

VTransco Extension of Time to File compliance Filings. On February 3, 2020, the FERC granted VTransco's request that the deadline for submitting its compliance filings be extended until July 31, 2020—the date of the TOs' next annual informational filing for regional formula rates. VTransco stated that the "extension of time will avoid unnecessary duplication of effort by otherwise requiring VTransco to submit multiple compliance filings over the coming months before the details of the PTOs' regional compliance filing are finalized and will enable the Commission to review all of VTransco's compliance filings at the same time, thereby enhancing the efficiency of the regulatory process."

- ***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"*).[165] 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.[166] CAISO requested clarification and PG&E requested rehearing or in the alternative clarification of *Order 861*. On September 16, 2019, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending.

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

In *Order 841*[167] (*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*.[168] All comments filed in response to the *Storage NOPR* will be incorporated by reference into Docket No. RM18-9 and further comments regarding the proposed distributed energy resource aggregation reforms, including comments regarding the April 10-11 technical conference in AD18-10,[169] were also to be filed in RM18-9. On June

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[164] *Public Util. Trans. Rate Changes to Address Accumulated Deferred Income Taxes*, 165 FERC ¶ 61,117 (Nov. 15, 2018) ("*ADIT NOPR*").

[165] *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).

[166] *Order 861* was published *Fed. Reg.* on July 26, 2019 (Vol. 84, No. 144) pp. 36,374-36,387.

[167] *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*").

[168] *Elec. Storage Participation in Mkts. Operated by Regional Trans. Orgs. and Indep. Sys. Operators*, 157 FERC ¶ 61,121 (Nov. 17, 2016) ("*Storage NOPR*").

[169] 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

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.

On September 5, the FERC requested that each of the RTO/ISOs provide responses to data requests seeking information on their policies and procedures that affect DER interconnections. The RTO/ISO responses were due and were filed on October 7, 2019. Comments on the responses were filed by 8 parties, including comments addressing ISO-NE's responses by MA DPU, MA DOER and MA AG (collectively, "Massachusetts"), MMWEC, AEE, EEI and NRECA. This matter is pending before the FERC.

- ***Order 860*: Data Collection for Analytics & Surveillance and MBR Purposes (RM16-17)**

On July 18, 2019, the FERC issued *Order 860*.[170] *Order 860*, issued three years after the FERC's *Data Collection NOPR,*[171] (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 ***not*** 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,[172] 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. Requests for rehearing and/or clarification of *Order 860* were submitted by EEI, Fund Management Parties, Joint Consumer Advocates, NRG/Vistra, Starwood Energy Group, and TAPS. On September 16, 2019, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending.

MBR Database. On January 10, 2020, the FERC issued a notice that updated versions of the XML, XSD, and MBR Data Dictionary are available on the FERC's website and that the test environment for the MBR Database is now available and can be accessed on the MBR Database webpage.

Feb 27, 2020 Technical Conference. On February 27, 2020, FERC staff hold a technical workshop on the relational database being built in accordance with *Order 860* ("MBR Database"). The workshop will take

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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.

170 *Data Collection for Analytics and Surveillance and Market-Based Rate Purposes*, 168 FERC ¶ 61,039 (July 18, 2019) ("*Order 860*").

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

172 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.

place from 9:00 a.m. to 12:30 p.m. (EST) in the Commission Meeting Room. All interested persons are invited to attend. For those unable to attend in person, access to the meeting will be available via webcast.

- **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").[173] The Version 003.2 Standards include NAESB's Version 003.1 revisions, which remain pending before the FERC following a July 2016 NOPR.[174] 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[175] 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.[176] 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.[177] 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. Further reply comments (also submitted in PL19-3, were submitted by a large group of state public utility commissions, public power utilities, electric cooperatives, consumer advocates, industrial users of electricity, and associations, TEC-RI and the RI Manufacturers Association. Since the last Report, SPP transmission owners submitted comments in

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[173] *Standards for Business Practices and Communication Protocols for Public Utilities*, 167 FERC ¶ 61,127 (May 16, 2019) ("*NAESB WEQ v. 003.2 Standards NOPR*").

[174] *Standards for Business Practices and Communication Protocols for Public Utilities*, 156 FERC ¶ 61,055 (July 21, 2016), ("*WEQ v. 003.1 NOPR*").

[175] 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.

[176] *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 166 FERC ¶ 61,207 (Mar. 21, 2019) ("*ROE Policy NOI*").

[177] The *ROE Policy NOI* was published in the *Fed. Reg.* on Mar. 28, 2019 (Vol. 84, No. 61) pp. 11,769-11,777.

light of *Opinion 569*[178] and statements made by the FERC concurrent with the issuance of *Opinion 569*. 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.[179] 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 comment on a variety of transmission incentives-related issues. Initial comments were due June 26, 2019[180] and were filed by more than 70 parties, including by Avangrid, Eversource, Exelon, Invenergy, MMWEC/NHEC, National Grid, 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. Reply comments were due on or before Aug 26, 2019, and nearly 50 sets of reply comments were submitted, including from the entities identified in PL19-4 and from Avangrid, EMCOS, Eversource, Exelon, LS Power, National Grid, and NESCOE. Since the last Report, a group of organizations, led by the CT PURA,[181] submitted comments on October 9, 2019 highlighting areas of agreement among them, and urging the FERC "to give these positional agreements consideration in assessing whether—and, if so, how—to modify current transmission incentive policies." This matter is pending before the FERC.

- **NOI: Certification of New Interstate Natural Gas Facilities (PL18-1)**

On April 19, 2018, the FERC announced its intention to revisit its approach under its 1999 Certificate Policy Statement to determine whether a proposed jurisdictional natural gas project is or will be required by the present or future public convenience and necessity, as that standard is established in NGA Section 7. Specifically, the NOI[182] 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,[183] comments were due on

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[178] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569, 169 FERC ¶ 61,129 (2019) ("*Opinion 569*").

[179] *Inquiry Regarding the Commission's Elec. Trans. Incentives Policy*, 166 FERC ¶ 61,208 (Mar. 21, 2019) ("*Electric Transmission Incentives Policy NOI*").

[180] 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.

[181] The group of organizations included CT PURA, DT CEEP, NH PUC, VT DPS, MN PUC, DC PUC, PA PUC, MA AG, CT AG, CT OCC, MMWEC, NHEC, TAPS, and APPA.

[182] The NOI was published in the *Fed. Reg.* on Apr. 26, 2018 (Vol. 83, No. 80) pp. 18,020-18,032.

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

or before July 25, 2018. Literally thousands of individual and mass-mailed comments were filed. This matter remains pending before the FERC.

XIII.Natural Gas Proceedings

For further information on any of the natural gas proceedings, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com).

- **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*[184] 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.[185] 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."[186] 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.[187] 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, 2018the 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.[188]

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

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

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

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

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

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

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[189] 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.[190]

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:
  - ***Constitution Pipeline (CP13-499) and Wright Interconnection Project (CP13-502)***
    - Constitution Pipeline Company and Iroquois Gas Transmission (Wright Interconnection) concurrently filed for Section 7(c) certificates on June 13, 2013.
    - 650,000 Dth/d of firm capacity from Susquehanna County, PA (Marcellus Shale) through NY to Iroquois/Tennessee interconnection (Wright Interconnection).
    - New 122-mile interstate pipeline.
    - Two firm shippers: Cabot Oil & Gas and Southwestern Energy Services.
    - Final EIS completed on Oct 24, 2014.
    - Certificates of public convenience and necessity granted Dec 2, 2014.
      - By letter order issued July 26, 2016, the Director of the Division of Pipeline Certificates (Director) granted Constitution's requested two-year extension of time to construct the project.
      - Construction was expected to begin Spring 2016 (after final Federal Authorizations), but has been plagued by delays (see below).
    - On April 22, 2016, New York State Department of Environmental Conservation (NY DEC) denied Constitution's application for a Section 401 permit under the Clean Water Act.

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

[190] 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.

- 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.[191] 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.[192]
  - 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.[193] On September 14, 2018, Constitution filed a petition for review in the U.S. Court of Appeals for the D.C. Circuit.[194]
- On May 16, 2016, the New York Attorney General filed a complaint against Constitution at the FERC (CP13-499) seeking a stay of the December 2014 order granting the original certificates, as well as alleging violations of the order, the Natural Gas Act, and the Commission's own regulations due to acts and omissions associated with clear-cutting and other construction-related activities on the pipeline right of way in New York.
  - In July 2016, the FERC rejected the NY AG's filing as procedurally deficient, and declined to stay of the Certificate Order. The NY AG sought rehearing, and the Commission denied rehearing on November 22, 2016, noting again that the NY AG's complaint was still procedurally deficient.
- Tree felling and site preparation continues, but the long-term status of the pipeline is currently unknown.
- On June 25, 2018, Constitution requested a further 2-year extension of the deadline to complete construction of its project, given the delays caused by the on-going fight over 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

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

192 *Id.* at P 23.

193 *Constitution Pipeline Co., LLC*, 164 FERC ¶ 61,029 (2018) (September 2018 Waiver Rehearing Order).

194 *Constitution*, Petition for Review in U.S. Court of Appeals for the D.C. Circuit, Docket No. CP18-5-000 (filed Sep. 14, 2018).

answered some of the opposition pleadings. The FERC granted the requested two-year extension of time on November 5, 2018.[195]

- 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"). On November 8, 2019, the FERC dismissed or denied the requests for rehearing.[196]

- **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.[197] Those orders have been challenged on appeal to the US Court of Appeals for the Second Circuit (19-1610).
    - 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*.[198] 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,[199] 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, 2017.[200] 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

[195] *Constitution Pipeline Co.*, 165 FERC ¶ 61,081 (Nov. 5, 2018), *reh'g denied*, 169 FERC ¶ 61,102 (Nov. 8, 2019).

[196] *Constitution Pipeline Co.*, 169 FERC ¶ 61,102 (Nov. 8, 2019) (order on rehearing).

[197] *Nat'l Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 167 FERC ¶ 61,007 (Apr. 2, 2019).

[198] *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).

[199] 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).

[200] *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*").

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.[201] 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 was granted on January 31, 2019.
- On August 8, 2019, the NY DEC again denied Applicants request for a Water Quality Certification, and as directed by the Second Circuit,[202] provided a "more clearly articulate[d] basis for denial."
- On August 27, Applicants requested an additional order finding on additional grounds that the NY DEC waived its authority over the Northern Access 2016 Project under Section 401 of the CWA, even if the NY DEC and Sierra Club prevail in their currently pending court petitions challenging the basis for the Commission's Waiver Order.[203]

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).

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201 *Nat'l Fuel Gas Supply Corp. v. NYSDEC et al*. (2d Cir., Case No. 17-1164).

202 Summary Order, *Nat'l Fuel Gas Supply Corp. v. N.Y. State Dep't of Envtl. Conservation*, Case 17-1164 (2d Cir, issued Feb. 5, 2019).

203 *See Sierra Club v. FERC*, No. 19-01618 (2d Cir. filed May 30, 2019); *NYSDEC v. FERC*, No. 19-1610 (2d. Cir. filed May 28, 2019) (consolidated).

- **ISO-NE's Inventoried Energy Program (Chapter 2B) Proposal (19-1224***; 19-1247; 19-1252; 19-1253)(consolidated)**
Underlying FERC Proceeding: ER19-1428[204]
Petitioners: ENECOS (19-1224); MA AG (19-1247); NH PUC/NH OCA (19-1252); RENEW (19-1253)

On October 24, 2019, ENECOS[205] petitioned the DC Circuit Court of Appeals for review of the FERC's August 6, 2019 Chapter 2B Notice that ISO-NE's Chapter 2B Proposal took effect by operation of law. MA AG (November 25), the NH PUC and NH OCA (December 3), and RENEW Northeast (December 3) similarly filed separate appeals. All of the cases were ultimately consolidated on December 30, 2019 (with 19-1224 as the lead docket). Petitioners' initial submissions, procedural and dispositive motions were filed on January 6, 2020. Since the last Report, the FERC submitted a motion asking for 60 days between the filing of Petitioners' opening brief and the FERC's brief in response, and filed the Certified Index to the Record. Also, on January 21, the Court granted the motions to intervene of NEPOOL, ISO-NE, NEPGA, Calpine, and the MPUC.

- ***Order 841* (19-1142, 19-1147) (consol.)**
Underlying FERC Proceeding: RM16-23; AD16-[206]
Petitioners: NARUC, APPA et al.

NARUC and APPA et al.[207] petitioned the DC Circuit Court of Appeals for review of *Orders 841* and *841-A* (Electric Storage Participation in RTO/ISO Markets). The cases have been consolidated, with 19-1142 as the lead docket. Docketing statements, statement of issues and interventions,[208] Petitioners' and Intervenors for Petitioners' briefs, and FERC's Respondent Brief have been filed. Future deadlines include: Joint Briefs of Environmental and Industry Intervenors for Respondent (Feb. 7, 2020); Petitioners' and Intervenor for Petitioners Reply Briefs (Mar. 2, 2020); Deferred Joint Appendix (Mar. 9, 2020); and Final Briefs (Mar. 16, 2020).

- **FCM Pricing Rules Complaints (15-1071**, 16-1042) (consol.)**
Underlying FERC Proceeding: EL14-7,[209] **EL15-23**[210]
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).[211] Finding that "the FERC failed to adequately explain why its rationale [for rejecting price lock-in and capacity carry forward rules] in PJM – which seems to foreclose signing off on a Tariff scheme like ISO-NE's – does not apply even more forcefully to the scheme it accepted in the Orders [appealed from]," the DC Circuit granted the Petitions and remanded the case to the FERC for further proceedings in which the FERC, in order to accept the changes filed, must provide some analysis and explanation why it changed course. The remand is now pending before the FERC.

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[204] 162 FERC ¶ 61,127 (Feb. 15, 2018) ("*Order 841*"); 167 FERC ¶ 61,154 (May 16, 2019) ("*Order 841-A*").

[205] "ENECOS" are Belmont; Block Island Utility District; Braintree; Energy New England ("ENE"); Georgetown Municipal Light Department; Groveland; Hingham; Littleton; Merrimac; Middleborough; Middleton; North Attleborough; Norwood; Pascoag; Reading; Rowley; Stowe; Taunton; and Wellesley.

[206] 162 FERC ¶ 61,127 (Feb. 15, 2018) ("*Order 841*"); 167 FERC ¶ 61,154 (May 16, 2019) ("*Order 841-A*").

[207] "APPA et al." are the American Public Power Assoc. ("APPA"), National Rural Elec. Coop. Assoc. ("NRECA"), Edison Electric Institute ("EEI"), and American Municipal Power, Inc. ("AMP").

[208] Interventions were filed and granted for Southern California Edison, Energy Storage Association ("ESA"), Transmission Access Policy Study Group ("TAPS"), Solar Energy Industries Association ("SEIA"), AEE, NRDC, EDF, Vote Solar, MISO, and NextEra Energy Resources.

[209] 150 FERC ¶ 61,064 (Jan. 30, 2015); 146 FERC ¶ 61,039 (Jan. 24, 2014).

[210] 154 FERC ¶ 61,005 (Jan. 7, 2016); 150 FERC ¶ 61,067 (Jan. 30, 2015).

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

Other Federal Court Activity of Interest

- **PG&E Bankruptcy (19-71615) (9th Cir.)**
  Underlying FERC Proceeding: EL19-35, EL19-36[212]
  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."[213] 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. The PG&E motion was granted on August 1.

Since the last Report, PG&E submitted its Reply Brief. This matter remains before the Ninth Circuit.

- **First Energy Solutions Bankruptcy (18-3787) (6th Cir.)**
  Petitioner: FERC

In this proceeding, the FERC appealed an Ohio bankruptcy court's August 2018 ruling that blocked the FERC from taking *any* action on FirstEnergy Solutions Corp.'s agreement with Ohio Valley Electric Corp. (a power purchase agreement that FES seeks to reject as part of its bankruptcy proceedings). The FERC 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 was decided. 2-1, on December 12, 2019.[214]

The Sixth Circuit concluded that the bankruptcy court has jurisdiction to decide whether FES may reject the contracts, but that its injunction of FERC in this case was overly broad (beyond its jurisdiction), and its standard for deciding rejection was too limited. Therefore, the Sixth Circuit affirmed in part, reversed in part, and remanded the matter to the bankruptcy court for further consideration. In reaching its decision, the Sixth Circuit held that "the public necessity of available and functional bankruptcy relief is generally superior to the necessity of FERC's having complete or exclusive authority to regulate energy contracts and markets ... the bankruptcy court has jurisdiction to decide whether FES, as a Chapter 11 debtor-in-possession, may reject the [ ] contracts, meaning that FES can reject the contracts subject to proper bankruptcy court approval and FERC cannot independently prevent it." The Sixth Circuit went on to hold, however, that "when a Chapter 11 debtor moves the bankruptcy court for permission to reject a filed energy contract that is otherwise governed by FERC, via the FPA, the bankruptcy court must consider the ***public interest*** and ensure that the equities balance in favor of rejecting the contract, and it must invite FERC to participate and provide an opinion in accordance with the ordinary FPA approach (e.g., under the Mobile–Sierra doctrine), within a reasonable time." The Court noted that a "reasonable delay in this remand may be much longer that it would be in an ordinary case" given the bankruptcy court's earlier "improper and absolute injunction preventing FERC from conducting its assessment."

On January 27, the FERC petitioned for *en banc* rehearing of the December 12 decision. That petition is pending before the 6th Circuit.

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[212] *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).

[213] Declaratory Judgment at 1-2, *PG&E v. FERC*, (Bankr. N.D. Cal. June 7, 2019).

[214] *In re: FirstEnergy Solution Corp., et al.*, No. 18-3767, ___ F.3d ___; 2019 WL 6767004 (6th Cir. Dec. 12, 2019).

- **PennEast Project (18-1128)**
  Underlying FERC Proceeding: CP15-558[215]
  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")[216] 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 was scheduled for October 4, 2019. However, on October 1, the court removed the cases from the oral argument calendar and will hold the cases in abeyance "pending final disposition of any post-dispositional proceedings in the Third Circuit or proceedings before the United States Supreme Court resulting from the Third Circuit's decision in No. 19-1191 (In re: PennEast Pipeline Company, LLC (3rd Cir. Sep. 10, 2019)), or other action that resolves the obstacle PennEast poses". That decision held that the Eleventh Amendment barred condemnation cases brought by PennEast in federal district court in New Jersey to gain access to property owned by the State or its agencies, thus calling into question the viability of PennEast's proposed project route, and the certificates issued in the underlying case. Until the Third Circuit case is resolved, the DC Circuit will not take up this case.

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[215] *PennEa*st *Pipeline Co., LLC*, 162 FERC ¶ 61,053 (Jan. 19, 2018), *reh'g denied*, 163 FERC ¶ 61,159 (May 30, 2018).

[216] 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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