NEPOOL
NEW ENGLAND POWER POOL

David T. Doot
Secretary

September 30, 2021

VIA ELECTRONIC MAIL

TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

RE: Supplemental Notice of October 7, 2021 NEPOOL Participants Committee Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that the October meeting of the Participants Committee will be held **in person on *Thursday*, October 7, 2021, at 10:00 a.m. at the Colonnade Hotel, 120 Huntington Avenue, Boston, MA in the Huntington Ballroom** for the purposes set forth on the attached agenda and posted with the meeting materials at nepool.com/meetings/.

For your information, the October 7 meeting will be recorded. 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.

This will be our first in-person meeting since we moved to virtual meetings in response to the COVID-19 pandemic more than a year and a half ago. We have included here the safety protocols that will be in effect for in-person attendance at the October 7 Participants Committee meeting. In summary, only those who are fully vaccinated, and have provided in advance of the meeting verification of full vaccination, will be permitted to attend in person. Pursuant to the City of Boston's mask mandate, all attendees must wear masks or face coverings at all times except when actively eating or drinking. Additional safety measures are outlined in the protocols. An e-mail regarding meeting registration and more detailed instructions for providing verification of vaccination will be sent under separate cover.

As with any in-person meeting, there will be COVID-related risks associated with in-person attendance at the October 7 Participants Committee meeting, but there are also substantial benefits from being together in-person. Efforts have been made to reduce the risks and to ensure that no unvaccinated people attend the meeting, but each of you will need to perform your own risk/benefit calculus in deciding whether to participate remotely or in-person. We look forward to seeing those who decide to attend in person as your elected officers work to maximize the value and benefit of the stakeholder process in the region.

For those who otherwise attend NEPOOL meetings but plan to participate in the October 7 meeting virtually, please use the following dial-in information: **866-803-2146; Passcode: 7169224.** To join using WebEx, click this link and enter the event password **nepool**.

There are a limited number of rooms available at the Colonnade Hotel for the evening before the October 7 meeting. If you wish to take advantage of the arrangements that have been made, please contact Kathryn Dube (kdube@daypitney.com) to confirm availability and secure a room.

As indicated in the initial notice to you, please also note the following two items requiring your attention at this time:

- **Wednesday, November 3 Sector Meetings with ISO Board Panels** – The next Sector meetings with the ISO Board are scheduled to be held in person on Wednesday, November 3. The ISO has requested that proposed agendas and supporting materials for those meetings be provided on or before ***Friday, October 15***. Materials can be sent directly to Maria Gulluni at mgulluni@iso-ne.com and Pat Gerity at pmgerity@daypitney.com. We are also working to set up virtual meetings between Sectors and state officials for those interested. We will provide further details as plans are finalized.

- **2022 NEPOOL Officers** – Each Sector needs to identify for us no later than ***Monday, November 1*** the voting member chosen by that Sector to serve as its 2022 Participants Committee officer. The Participants Committee will then select the Chair from among those Sector-selected officers, using the required voting process for that selection. We have included with this notice a memorandum that provides more information about the selection process.

Stay safe—stay well.

Respectfully yours,

/s/

David T. Doot, Secretary

FINAL AGENDA

1. To approve the draft minutes of the September 2, 2021 Participants Committee meeting. The draft preliminary minutes of that meeting, marked to show changes from the draft circulated with the initial notice, are included with this supplemental notice and posted with the meeting materials.

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

3. To receive an ISO Chief Executive Officer report. The October CEO report will be circulated and posted in advance of the meeting.

4. To receive a report from the ISO Chief Operating Officer on the following:
   a. Operations Report Highlights.
   b. Annual Work Plan
   c. Operational Impact of Extreme Weather Events

   Materials for these items will be circulated and posted in advance of the meeting.

5. To consider, and take action, as appropriate, on the following proposed budgets:
   a. 2022 ISO-NE Operating and Capital Budgets; and
   b. 2022 NESCOE Budget.

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

6. To consider, and take action, as appropriate, on the removal of notarization requirements from Sections II.A.2 and II.A.3 of the Financial Assurance Policy. Background materials and a draft resolution are included with this supplemental notice and posted with the meeting materials.

7. To consider and take action, as appropriate, on changes to Attachment K to Section II of the Tariff related to the treatment of existing resources in transmission needs assessments and public policy transmission studies. Background materials and a draft resolution are included with this supplemental notice and posted with the meeting materials.

[continued on next page]

8. To consider, and take action, as appropriate, on draft NEPOOL comments to be submitted in response to the FERC's Transmission Planning & Allocation/Generation Interconnection Advanced Notice of Proposed Rulemaking. Background materials and a draft resolution are included with this supplemental notice and posted with the meeting materials.

9. To consider and take action, as appropriate, on recommendations by the Membership Subcommittee to adopt a definition of "Associate Non-Voting Participant" (deleting the definition of Fuels Industry Participant), determining each Fuels Industry Participant to be an Associate Non-Voting Participant, and delegating to the Subcommittee the authority to approve applications for membership, subject to the Standard Membership Conditions, Waivers and Reminders, received from gas industry participants or energy sector trade associations. Background materials and draft resolutions are included with this supplemental notice and posted with the meeting materials.

10. To receive a report on current contested matters before the FERC and the Federal Courts. The litigation report will be circulated and posted in advance of the meeting.

11. To receive reports from Committees, Subcommittees and other working groups:
    - Markets Committee
    - Reliability Committee
    - Transmission Committee
    - Budget & Finance Subcommittee
    - Others

12. Administrative matters.

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

eff. September 22, 2021

NEPOOL
NEW ENGLAND POWER POOL

**Protocols for In-Person Attendance at NEPOOL Meetings
During the Covid-19 Pandemic**

These protocols for return to in-person NEPOOL meetings are effective as of the date above and may be modified from time to time as guidelines from the U.S. Centers for Disease Control ("CDC"), applicable state or local requirements, or circumstances change.

Background

The Protocols provided herein outline recommended and preventative measures to reduce the COVID-related risks associated with attendance in person at NEPOOL meetings.[1] Measures include safety precautions individuals must take while at in-person meetings. In-person attendance will follow and adhere to the latest CDC guidelines (as well as any additional, applicable state or local requirements that may be in place). As with any in-person meeting, there will be COVID-related risks associated with in-person attendance. **Each in-person attendee should perform their own risk/benefit calculus in deciding whether to participate in-person or remotely.**

Safety Precautions

Proof of Full Vaccination Required. To attend a NEPOOL meeting in person, each attendee must be fully vaccinated.[2] Proof of vaccination (e.g., a copy of a completed COVID-19 Vaccination Record/Card) must be provided to NEPOOL counsel (pmgerity@daypitney.com) in advance of the meeting.[3] An attendee who is unable to provide a copy of a completed COVID-19 Vaccination Record may sign and provide a COVID-19 Vaccination Status Attestation as an alternate form of proof. All such records will be maintained by NEPOOL Counsel in a confidential file. Those who are not vaccinated, or who have not timely provided proof of vaccination, will not be permitted in the meeting room and will be encouraged to participate by teleconference/WebEx. An individual's ability to attend a meeting in person will be restored following proof of vaccination.

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[1] 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.

[2] A person is considered fully vaccinated: (i) 2 weeks after their second dose in a 2-dose series, such as the Pfizer or Moderna vaccines, or (ii) 2 weeks after a single-dose vaccine, such as Johnson & Johnson's Janssen vaccine. If you don't meet either of these criteria, regardless of age, you are NOT fully vaccinated.

[3] Proof of vaccination of ISO employees or representatives, as a condition of their in-person attendance, will be confidentially (i) collected and maintained by the ISO and (ii) verified by an ISO committee officer with NEPOOL counsel in advance of attendance at a meeting.

eff. September 22, 2021

Registration Required; Contact Tracing. Registration for in-person attendance will be required and the Committee Secretary will keep a separate record of all individuals in attendance in person for the purpose of later contact tracing. Specific contact tracing information is confidential and NEPOOL will not use this information for any other reason. Contact tracing information will be kept for 28 days and destroyed thereafter.

Attendance In-Person Not Permitted if Experiencing Covid-19 Indicative Symptoms. Individuals should not attend an in-person meeting if they are experiencing new or worsening symptoms of any of the following in the last 14 days:

- Fever of 100.4 ⁰F (38.0 ⁰C) or higher
- Chills
- Cough
- Shortness of breath or difficulty breathing
- Fatigue
- Muscle or body aches
- Headache
- New Loss of Taste or Smell
- Sore Throat
- Congestion or runny nose
- Nausea or vomiting
- Diarrhea

Attendance In-Person Not Permitted if Recent Exposure to Covid-19-Positive Individual. Individuals should not attend in-person meetings if they have had a likely exposure to a COVID-19 positive individual in the last 14 days.

Physical Distancing. The opportunity for physical distancing at meeting tables will be provided where and as possible, but will not be enforced. Attendees are encouraged, whenever otherwise possible, to separate themselves by 6 feet of distance. Seating at round tables should be limited to six or fewer.

Masks. If and as required by CDC guidelines or by the requirements of the state or locale in which the meeting is taking place, face coverings (“masks”) shall be worn. Where physical distancing cannot be maintained, it is recommended that attendees wear masks whenever they are not seated, including while in transit to or from their seat and while standing in lines or in the room.

Sanitizing. Hand sanitizer and wipes will be made available at each meeting. Additional arrangements will be implemented to facilitate sanitation measures. (e.g. All microphones will be positioned and sanitized prior to arrival. Microphones will also be sanitized at lunch and at the end of the day. Alcohol sanitizing wipes will be available for attendees to utilize during the meeting to sanitize the microphones between users.)

eff. September 22, 2021

Reporting and Communicating a Positive COVID-19 Result

In the event of a COVID-19-positive test result, an individual that attended an in-person meeting within 14 days of that result should immediately contact NEPOOL Counsel (pmgerity@daypitney.com) to report their COVID-19 status. NEPOOL Counsel will maintain the individual's privacy while notifying those that attended the meeting in person of the positive test result. Please be advised that all health information is private and strictly confidential and will only be shared on a need-to-know basis to confirm and trace any contact with the positive tester at a NEPOOL in-person meeting and contact those who may have been exposed. Any notice of a COVID-19-positive test result will be kept for 28 days and destroyed thereafter.

Remote Participation

For those individuals who are otherwise authorized to attend a NEPOOL meeting, but choose not to, or because of safety measures are unable to, attend meetings in person, remote participation (i.e. by teleconference and/or by WebEx) will continue to be made available.

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Pat Gerity, NEPOOL Counsel

DATE: September 23, 2021

RE: 2022 Participants Committee Officer Elections

In order to ensure that the selection process requirements in the Participants Committee Bylaws for 2022's Participants Committee officers can be timely completed, we need each Sector to indicate, no later than **Monday, November 1, 2021,** who the Sector has selected to serve as the Sector's Participants Committee officer. A description of the qualifications, responsibilities, and expectations of the Sector officers selected has been included with this memorandum. We urge each of you to work within your Sectors to select your Sector's 2022 Participants Committee officer.

By way of reminder, the Bylaws require that one voting member from each Sector be selected by a majority of all the voting members in its Sector (i) to serve as a nominee for Chair of the Participants Committee and (ii) if not elected Chair, to serve as a Committee Vice-Chair. A secret written balloting process will then be conducted to elect the 2022 Chair from among the Participants Committee officers selected by each of the Sectors. To allow time for that balloting process ahead of the December 2 Annual Meeting, as required by the Bylaws, we need the officers to be identified by November 1, 2021.

If any Sector needs assistance in conducting the vote for its Sector officer, please let us know (preferably no later than October 21). We would be pleased to help however we can. Also, if you have any questions, please contact me at pmgerity@daypitney.com or (860) 275-0533.

Participants Committee Sector Officer Qualifications, Responsibilities, and Expectations

Qualifications: A Participants Committee Chair or Vice-Chair must be a voting member of the Participants Committee. Per the Participants Committee Bylaws, one voting member from each active Sector of the Participants Committee is to be selected to serve as the Vice-Chair of the Sector "by a majority of all the voting members in its Sector." The Chair is selected from among the nominated Vice-Chairs using the balloting procedures in the Bylaws.

Responsibilities and Expectations of Participants Committee Sector Vice-Chairs:

1. Help to build and maintain a collegial and productive working relationship with other Committee officers and members, ISO management, and state officials participating in Committee activities.

2. Communicate routinely and effectively with other members of the Sector:

    a. To help ensure that members have the information needed to support informed and active Committee participation;

    b. To ensure that the officer has sufficient information to provide to the other officers, ISO management and staff, and state and federal officials a fair and objective report of Sector members' positions and sensitivities on regional matters; and

    c. To report objectively to Sector members information, questions, positions, perspectives, and sensitivities of or from the other Sectors, the ISO, and state officials that are provided to the Officer to be shared with the Sector.

3. Attend and lead or support planning for and participation in Participants Committee meetings, including (a) participation in pre-planning conference calls and in-person meetings to identify and confirm discussion and consent agenda topics and materials, meeting logistics and orderly flow of business at Committee meetings, and (b) serving as Chair if and as needed for a meeting or portions of a meeting at which the Chair is not able to preside.

4. Coordinate and organize Sector members when appropriate, including for meaningful participation by the Sector members in the semi-annual meetings with the ISO Board of Directors, state officials and FERC representatives.

5. Ensure that the Sector is fairly and objectively represented at other committee and working group meetings and meetings among Officers, ISO management and state officials, and that the Officer or representative is reasonably informed as to the perspectives and sensitivities of the Sector members.

6. With the other NPC Officers, review and comment on NEPOOL filings or pleadings, raising awareness of any Sector-specific sensitivities.

7. Serve, or designate an appropriate Sector member to serve, on the Joint Nominating Committee that recommends to the Participants Committee for endorsement a slate of candidates for membership on the ISO Board of Directors.

9/23/2021

PRELIMINARY

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held via teleconference beginning at 10:00 a.m. on Thursday, September 2, 2021. A quorum, determined in accordance with the Second Restated NEPOOL Agreement, was present and acting throughout the meeting. Attachment 1 identifies the members, alternates and temporary alternates who participated in the teleconference meeting.

Mr. David Cavanaugh, Chair, presided and Mr. Sebastian Lombardi, Assistant Secretary, recorded.

APPROVAL OF JULY 21 AND AUGUST 5, 2021 MEETING MINUTES

Mr. Cavanaugh referred the Committee to the preliminary minutes of the July 21, 2021 morning meeting and the August 5, 2021 meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of those meetings were unanimously approved as circulated, with an abstention by Mr. Michael Kuser's alternate recorded.

CONSENT AGENDA

Mr. Cavanaugh 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 as circulated, with an abstention on behalf of Mr. Kuser's alternate recorded.

ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), referred the Committee to the summaries of the ISO Board and Board Committee meetings that had occurred since the

August 5, 2021 Participants Committee meeting, which had been circulated and posted in advance of the meeting. There were no questions or comments on the summaries.

In response to a more general question regarding the timeline and efforts for incorporating Effective Load Carrying Capability (ELCC) into the region's arrangements, Mr. van Welie noted that incorporating ELCC was a top priority for the ISO. He explained that, from the preliminary work plan and thinking under way, the project may be multi-stage and multi-year, particularly given resource complications and energy constraints. He expressed an initial preference for implementing a marginal, rather than an average, ELCC approach. He indicated the ISO had a goal of implementing ELCC beginning in FCA18 for certain resources identified to have the largest impact, which he explained were those whose capacity ratings were determined to be the most overstated in the qualification process. A member suggested that the ISO consider a more holistic approach that would allow for other market enhancements to be applied more broadly to the capacity accreditation process.

ISO COO REPORT

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), began by referring the Committee to his September report, which had been circulated and posted in advance of the meeting. Dr. Chadalavada noted that the data in the report was through August 25, 2021, unless otherwise noted. The report highlighted: (i) Energy Market value for August 2021 was $534 million, up $71 million from the updated July 2021 value of $463 million and up $229 million from August 2020; (ii) August 2021 average natural gas prices were 22% higher than July 2021 average prices; (iii) average Real-Time Hub Locational Marginal Prices (LMPs) for August ($48.83/MWh) were 37% higher than July averages; (iv) average August 2021 natural gas prices and Real-Time Hub LMPs over the period were up 161% and 105%, respectively, from August 2020 average prices; (v) average Day-Ahead cleared physical energy during peak hours as percent of forecasted load was 100.4% during August (down from 100.6% in July), with the minimum value for the month (95.9%) on August 6; and (vi) Daily Net Commitment Period Compensation (NCPC) payments for August totaled \$2.3 million, which was down \$0.5 million from July 2021 and down \$1.1 million from August 2020. August NCPC payments, which were 0.4% of total Energy Market value, were comprised of: (a) \$1.9 million in first contingency payments (down \$0.3 million from July); (b) \$35,000 in second contingency, and (c) \$355,000 in distribution payments.

Regarding transmission outages, Dr. Chadalavada noted the planned outage of ~~,~~ line 354 from Northfield to Ludlow, which would be out of service through September 8 and again from September 25 to October 24, and would limit imports from New York (NY) to 700 MW and exports to NY to 1,200 MW. He also noted a second construction–related structure outage, which would be on lines 312/393 from October 14 to October 24 and again from November 29 to mid-December, limiting transfers with NY in both directions to 700 MW.

Dr. Chadalavada reported that registration was open for the Regional System Plan Public Meeting to be held virtually on October 6.

Dr. Chadalavada than referenced the impacts on the bulk power system of tropical storm Henri, which were minimal in comparison to those expected had it been a hurricane with landfall in Connecticut. He said that the system performed well, with only two 115 kV lines impacted (both restored that same day) and approximately 125,000 customer outages (most occurring in Rhode Island, where Henri landed). He compared those limited impacts to those experienced the year before in connection with Hurricane Isaias and those being experienced in Louisiana with Hurricane Ida.

In response to questions about the impacts of the storm, Dr. Chadalavada noted that nuclear units were not postured during the storm. The shutdown procedures for those units, given projected wind speeds and storm surge levels, made them unavailable for posturing. The units were not needed in any case because the generation cleared in the Day-Ahead Energy Market was more than sufficient to meet the low load levels experienced.

Dr. Chadalavada then contrasted the experience during Henri with conditions experienced on August 25 and 26. During that latter two-day period, load was in the 23,000-24,000 MW range, just above projections. Dr. Chadalavada highlighted for the Committee that despite higher LMPs and tight operating conditions during those days, no scarcity conditions occurred and there was no need for supplemental commitments. When prompted, he said that Day-Ahead prices for reserve products would likely have mitigated load sensitivity issues during this period. He confirmed that pay-for-performance conditions were not triggered during this period, and the region had not been close to violating any of its reserve requirements.

When asked about the timing for the Master/Local Control Center Procedure No. 2 (MLCC/2) declaration (which gives the ISO the permission to recall outages) made in anticipation of Henri, he explained the need for time to provide generation and transmission resources a reasonable opportunity to come back into service when needed should their outage be recalled. A member suggested that a revision to the procedure be considered to adjust the timing involved, allowing resources with shorter recall times to come back online closer to when needed.

More broadly, Dr. Chadalavada indicated that, in light of the events experienced over the prior year, particularly those in Texas and Louisiana, further discussion on preparation, recovery and the analysis of stress testing of markets would take place in connection with the planned discussion of the 2022 regional work plan at the October 7 Participants Committee meeting.

2022 ISO AND NESCOE BUDGETS

Mr. Robert Ludlow, ISO Vice President and Chief Financial & Compliance Officer, referred the Committee to the materials circulated and posted in advance of the meeting related to the proposed 2022 ISO Operating and Capital Budgets. He indicated that the materials ~~remain~~remained largely consistent with the more detailed presentation materials that were discussed with stakeholders and State officials in June. Mr. Ludlow highlighted that the key drivers of the 2022 budget increase included: (i) funding for an increase in the number of employees (particularly in the areas of markets development, system planning, modeling and information technology (IT)); (ii) contingency funding to allow for increased flexibility for additional studies or analyses as needed; and (iii) ~~and~~ capital costs associated with establishing a new platform as part of the region's transition to a cleaner grid.

Summarizing the process for budget review and approval, Mr. Ludlow said that the budgets had been reviewed with the Budget and Finance Subcommittee and State officials in August. Any additional comments from State officials on the budgets were due in approximately one week. The ISO would respond to any such comments and questions by late September. The ISO Board would review the budgets and all feedback received and the Participants Committee would be asked to vote on the final 2022 Budgets at its October 7 meeting. A FERC filing would then be made in mid-October.

In response to questions, Mr. Ludlow clarified how and in what areas the additional staff positions would be phased in. He also provided additional insight into how capital budgets were expected to be impacted over the subsequent five years, with Dr. Chadalavada reminding members of the market system platform replacement planned to take place during that timeframe. Mr. Ludlow noted that forecasts of the impact of depreciation costs in~~[?] future years~~ were included with the detailed presentation materials for the June Summer Meeting.

Turning to the 2022 NESCOE Budget, Mr. Cavanaugh referred the Committee to the NESCOE Budget materials posted in advance of the meeting. He noted that~~-~~ Ms. Heather Hunt, NESCOE Executive Director, was available for questions or comments. There were no questions or comments. He asked that members reach out to Ms. Hunt directly~~-~~ prior to the October 7 vote if any questions or comments arose.

REQUEST BY STORED SOLAR FOR WAIVER OF GIS OPERATING RULES AND GIS AGREEMENT

Mr. Paul Belval, NEPOOL Counsel, referred the Committee to the memorandum circulated and posted in advance of the meeting related to a request by Stored Solar J&WE, LLC (Stored Solar) for waiver of the Generation Information System (GIS) Operating Rules and GIS Agreement with APX Inc. to address a reporting error which occurred in the months of February and March 2021. Mr. Belval provided a summary of the request, noting that Stored Solar incorrectly entered the production by fuel type for each month, such that the biomass output was entered as natural gas output, and the natural gas output was entered as biomass output. He then provided an overview of the applicable GIS Operating Rules and the options for proceeding. Following Participant comments and a process overview by Mr. Sebastian Lombardi, the

Committee agreed without opposition to defer further consideration of the matter to the October 7 meeting, to allow for additional review and consideration of the waiver request.

LITIGATION REPORT

Mr. Lombardi referred the Committee to the August 31 Litigation Report that had been circulated and posted the day before the meeting. He highlighted the following:

(i) The first of two FERC technical conferences to discuss potential energy and ancillary services market reforms to be held on September 14;

(ii) The August 20th deficiency letter issued by the FERC in connection with the joint filing by Participating Transmission Owners Administrative Committee (PTO AC) and the ISO of tariff revisions addressing the treatment of certain behind-the-meter generation. The deficiency letter directed additional information be filed by September 20, and ~~will~~the filing would re-set the FERC's 60-day deadline to act on the proposed tariff revisions; and

(iii) The first meeting of the recently established Joint Federal-State Task Force on Electric Transmission ~~has~~had been scheduled for November 10, 2021 in connection with NARUC's annual meeting. ~~Members of the~~The Task Force~~, are~~ comprised all of the FERC Commissioners and 10 state ~~regulators~~commissioners, including New England State Commissioners Riley Allen (VT PUC) and Matt Nelson (Chair, MA DPU).

COMMITTEE REPORTS

Markets Committee (MC). Mr. William Fowler, the MC Vice-Chair, reported that the next MC meeting would be held September 13-14. An additional MC meeting would also be held on September 29.

Reliability Committee (RC). Mr. Robert Stein, the RC Vice-Chair, reported that a joint MC/RC meeting was scheduled for the afternoon of September 17 to consider potential next steps/actions for the joint Committees based on results from the Future Grid Reliability Study that ~~will~~would be provided to stakeholders during a Planning Advisory Committee (PAC) meeting scheduled for the morning of the 17th. The regularly-scheduled ~~RC~~September meeting ~~is scheduled for~~of the RC, to be held September 21, ~~and~~ would include a vote on Installed Capability Requirements (ICR) for FCA16.

Transmission Committee (TC). Mr. José Rotger, the TC Vice-Chair, reported that the scheduled September 28 TC meeting would include: (i) a vote on two sets of ISO-proposed changes to Attachment K of the Open Access Transmission Tariff (OATT), one set to expand resources included in the needs assessment and other planning studies and the other set to implement changes to the competitive transmission RFP provisions based on the lessons learned following the recent Boston Transmission RFP process; and (ii) continued discussion on the stakeholder proposal to eliminate from Schedule 11 of the Tariff operating and maintenance (O&M) charges for network upgrades associated with new generation interconnections.

Budget & Finance Subcommittee. Mr. Thomas Kaslow, the B&F Subcommittee Chair, reported that the next meeting was scheduled for October 4.

Membership Subcommittee. Ms. Sarah Bresolin, the Membership Subcommittee Chair, noted that a second meeting to consider potential changes to the characterization of the Fuels Industry Participant membership category (which had expanded to include a few trade association members) was scheduled for September 10. Ms. Bresolin indicated that proposed changes would be posted on the Subcommittee's NEPOOL website page, and would be further discussed at the September 10 meeting.

ADMINISTRATIVE MATTERS

Mr. Cavanaugh noted that the next Pathways Study meeting was scheduled for the afternoon of September 23 and would be held virtually. He reported that plans to begin meeting in person, beginning with the October 7 Participants Committee meeting, were proceeding. He thanked Participants for their responses to the questionnaire that had been circulated a few weeks before. He reported that more than 85% of NPC members and alternates who regularly attend meetings answered the questionnaire, all reporting that they were fully vaccinated, and more than 70% of the respondents indicating they would be comfortable attending in-person NEPOOL meetings in October, subject to various protocols. The information provided was informing efforts among ISO and NEPOOL Committee leadership to establish safety measures and protocols for a return to in-person meetings. Additional information regarding those measures would be shared in mid-September. Those interested in the aggregate questionnaire data were encouraged to contact Mr. Pat Gerity, NEPOOL counsel, directly.

Mr. Cavanaugh noted that the October 7 Participants Committee meeting would include, among other issues, a review of the 2022 work plan and votes on both the ISO and NESCOE 2022 budgets. Looking further ahead, he highlighted that the November Participants Committee meeting would be held on Wednesday, November 3, at the Hilton Boston Logan Airport and would be preceded by Sector meetings with ISO board members.

There being no other business, the meeting adjourned at 12:01 p.m.

Respectfully submitted,

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Sebastian Lombardi, Acting Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN
~~PARTICIPATING IN SEPT~~SEPTEMBER 2, 2021 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Actual Energy, Inc.	Supplier		John Driscoll	
Advanced Energy Economy	Fuels Industry Participant	Caitlin Marquis		
American Petroleum Institute	Fuels Industry Participant	Paul Powers		
AR Large Renewable Generation (RG) Group Member	AR-RG	Alex Worsley		
AR Small Load Response (LR) Group Member	AR-LR	Brad Swalwell		
Ashburnham Municipal Light Plant	Publicly Owned Entity		Brian Thomson	
Associated Industries of Massachusetts (AIM)	End User			Mary Smith
AVANGRID: CMP/UI	Transmission	Alan Trotta		
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
Borrego Solar Systems Inc.	AR-DG	Liz Delaney		
Boylston Municipal Light Department	Publicly Owned Entity		Brian Thomson	
BP Energy Company	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity			Dave Cavanaugh
Brookfield Renewable Trading and Marketing	Supplier	Aleks Mitreski		
Calpine Energy Services, LP	Supplier	Brett Kruse		Bill Fowler
Castleton Commodities Merchant Trading	Supplier			Bob Stein
Central Rivers Power	AR-RG		Dan Allegretti	
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
CLEAResult Consulting, Inc.	AR-DG	Tamera Oldfield		
Clearway Power Marketing LLC	Supplier			Pete Fuller
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	Brian Forshaw		
Connecticut Office of Consumer Counsel (CT OCC)	End User		Dave Thompson	
Conservation Law Foundation (CLF)	End User	Phelps Turner		
Consolidated Edison Energy, Inc.	Supplier	Norman Mah		
CPV Towantic, LLC (CPV)	Generation	Joel Gordon		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Dominion Energy Generation Marketing	Generation		Weezie Nuara	
DTE Energy Trading, Inc.	Supplier			José Rotger
Dynegy Marketing and Trade, LLC	Supplier	Andy Weinstein		Bill Fowler
Emera Energy Services	Supplier			Bill Fowler
Enel X North America, Inc.	AR-LR	Michael Macrae		
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Environmental Defense Fund	End User	Jolette Westbrook		
Eversource Energy	Transmission	James Daly	Dave Burnham	
Exelon Generation Company	Supplier	Steve Kirk	Bill Fowler	
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc.	Supplier	José Rotger		
Generation Group Member	Generation	Dennis Duffy	Abby Krich	
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Great River Hydro	AR-RG			Bill Fowler
Groton Electric Light Department	Publicly Owned Entity		Brian Thomson	
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQUS)	Supplier	Louis Guilbault	Bob Stein	
High Liner Foods (USA) Incorporated	End User		William P. Short III	
Hingham Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Holyoke Gas & Electric Department	Publicly Owned Entity		Brian Thomson	
Hull Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
Ipswich Municipal Light Department	Publicly Owned Entity		Brian Thomson	

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN
~~PARTICIPATING IN SEPT~~SEPTEMBER 2, 2021 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Jericho Power LLC (Jericho)	AR-RG	Mark Spencer		
Littleton (MA) Electric Light and Water Department	Publicly Owned Entity		Dave Cavanaugh	
Littleton (NH) Water & Light Department	Publicly Owned Entity		Craig Kieny	
Long Island Power Authority (LIPA)	Supplier		Bill Killgoar	
Maine Power LLC	Supplier	Jeff Jones		
Maine Public Advocate's Office	End User	Drew Landry		
Mansfield Municipal Electric Department	Publicly Owned Entity		Brian Thomson	
Maple Energy LLC	AR-LR			Doug Hurley
Marblehead Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Mass. Attorney General's Office (MA AG)	End User	Tina Belew	Ben Griffiths	
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity	Brian Thomson		
Mercuria Energy America, LLC	Supplier			José Rotger
Merrimac Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Michael Kuser	End User		Jason York	
Middleborough Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Middleton Municipal Electric Department	Publicly Owned Entity		Dave Cavanaugh	
National Grid	Transmission	Tim Brennan	Tim Martin	
Nautilus Power, LLC	Generation		Bill Fowler	
New Hampshire Electric Cooperative	Publicly Owned Entity	Steve Kaminski		Brian Forshaw; Dave Cavanaugh; Brian Thomson
New England Power Generators Association (NEPGA)	Fuels Industry Participant	Bruce Anderson	Dan Dolan	
NextEra Energy Resources, LLC	Generation	Michelle Gardner		
North Attleborough Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Norwood Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
NRG Power Marketing LLC		Pete Fuller		
Pascoag Utility District	Publicly Owned Entity		Dave Cavanaugh	
Paxton Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Peabody Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Princeton Municipal Light Department	Publicly Owned Entity		Brian Thomson	
PSEG Energy Resources & Trade LLC (PSEG)	Supplier		Eric Stallings	
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity		Brian Thomson	
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Brian Thomson	
Small RG Group Member	AR-RG	Erik Abend		
South Hadley Electric Light Department	Publicly Owned Entity		Brian Thomson	
Sterling Municipal Electric Light Department	Publicly Owned Entity		Brian Thomson	
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Sunrun Inc.	AR-DG			Pete Fuller
Taunton Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
The Energy Consortium	End User	Bob Espindola	Mary Smith	
Vermont Electric Cooperative	Publicly Owned Entity	Craig Kieny		
Vermont Electric Power Company (VELCO)	Transmission	Frank Ettori		
Vermont Energy Investment Corp (VEIC)	AR-LR		Doug Hurley	
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw
Versant Power	Transmission	Lisa Martin		
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Vitol Inc.	Supplier	Joe Wadsworth		
Wakefield Municipal Gas & Light Department	Publicly Owned Entity		Brian Thomson	
Wallingford DPU Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
West Boylston Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN
~~PARTICIPATING IN SEPT~~SEPTEMBER 2, 2021 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wheelabrator North Andover Inc.	AR-RG		Bill Fowler	

CONSENT AGENDA

Reliability Committee (RC)

From the previously-circulated notice of actions of the RC's September 20, 2021 meeting (Revision 1), dated September 21, 2021.[1]

1. FCA16 HQICC Values

Support the following Hydro-Québec Interconnection Capability Credit (HQICC) values for the sixteenth Forward Capacity Auction, which is associated with the 2025-2026 Capacity Commitment Period (FCA16), as recommended by the Reliability Committee at its September 21, 2021 meeting, with such further non-material changes as the Chair and Vice-Chair of the Reliability Committee may approve.

2025-2026 Capacity Commitment Period (CCP) Month	HQICC Values (MW)
June	923
July	923
August	923
September	923
October	923
November	923
December	923
January	923
February	923
March	923
April	923
May	923

The motion to recommend Participants Committee support was approved, with two oppositions in the Supplier Sector noted and nine abstentions (1 Generation, 6 Supplier, 2 Alternative Resource).

[continued on next page]

[1] RC 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. FCA16 ICR and Related Values

Support the following megawatt (MW) values that represent the New England Installed Capacity Requirement (ICR), Net Installed Capacity Requirement (Net ICR), Southeast New England Local Sourcing Requirement (LSR), Maine Maximum Capacity Limit (MCL), Northern New England MCL, and Capacity Demand Curves for the System and Capacity Zones based on the Marginal Reliability Impact (MRI) methodology for FCA16, as recommended by the RC at its September 21, 2021 meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

	2025-2026 CCP ICR Values (MW)
Installed Capacity Requirement	32,568
Net Installed Capacity Requirement	31,645
Southeast New England (SENE) Local Sourcing Requirement	9,450
Maine Maximum Capacity Limit	4,095
Northern New England (NNE) Maximum Capacity Limit	8,555

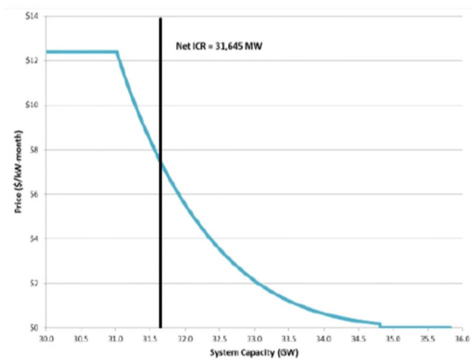


Figure 1: System Demand Curve
2025-2026 Capacity Commitment Period (CCP)

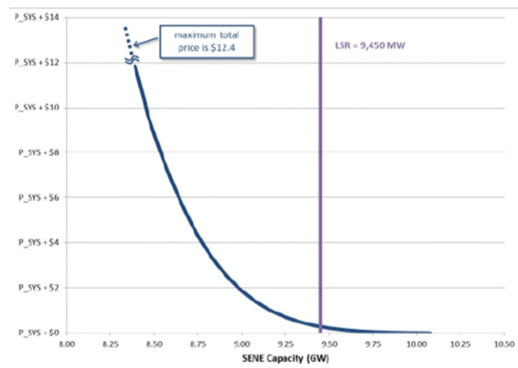


Figure 2: SENE Capacity Zone Demand Curve
2025-2026 CCP

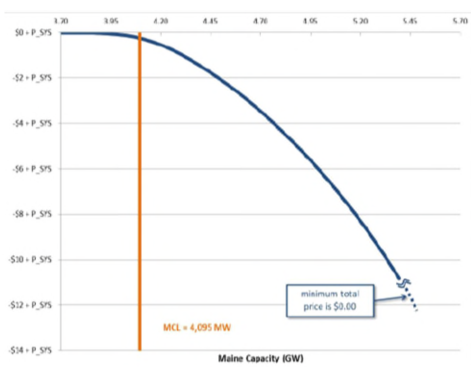


Figure 3: Maine Capacity Zone Demand Curve
2025-2026 CCP

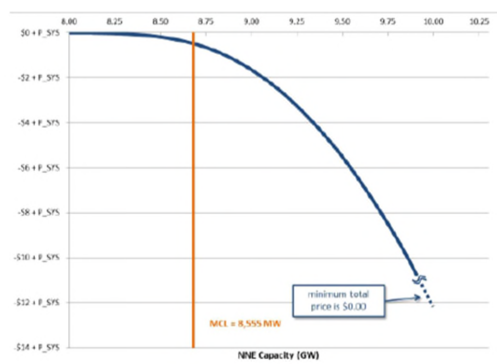


Figure 4: NNE Capacity Zone Demand Curve
2025-2026 CCP

The motion to recommend Participants Committee support was approved, with two oppositions in the Supplier Sector noted and eight abstentions (1 Generation, 5 Supplier, 2 Alternative Resource).

3. Changes to Appendix J to OP-16 (Periodic Review Changes)

Support revisions to Appendix J to ISO New England Operating Procedure (OP) No. 16 (OP16-J) (Transmission System Data, Instructions for Submission of Dynamics Data), which update the process for submittals of transmission system data, discontinue current transmission equipment user models for stability studies, update provisions of dynamic load modeling characteristics and add a requirement to provide "as built" characteristics for new equipment, all as recommended by the RC at its September 21, 2021 meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

The motion to recommend Participants Committee support was unanimously approved.

4. Changes to OP-21 (Generator Winter Readiness Survey Question Revisions)

Support revisions to OP-21 (Energy Inventory Accounting and Actions During an Emergency) which add and update Generator Winter Readiness Survey questions in order to enhance awareness of potential impacts of generator availability due to extreme cold weather and precipitation, as recommended by the RC at its September 21, 2021 meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

The motion to recommend Participants Committee support was unanimously approved.

5. Changes to OP-7 and Appendix A to OP-7 (Annual Review Changes)

Support annual review revisions to (i) OP-7 (Action in an Emergency), which modify instructions for current expectations and stipulate expectations for operator communications; and (ii) Appendix A to OP-7 (Instructions for Implementation of Manual Load Shedding), which enhance instructions to determine load to be shed and restored and update language in examples to illustrate enhanced instructions, all as recommended by the RC at its September 21, 2021 meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

The motion to recommend Participants Committee support was unanimously approved.

6. Changes to Appendix A to OP-2 (Biennial Review Changes)

Support revisions to Appendix A to OP-2 (Itemized Equipment), which include minor updates and edits to the itemized equipment list along with additional clarifications following a biennial review, as recommended by the RC at its September 21, 2021 meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

The motion to recommend Participants Committee support was unanimously approved.

7. Changes to OP- 19 (Annual Review Changes)

Support revisions to OP-19 (Transmission Operations), which include updates to the Reference section and formatting, attributions, grammar and composition changes, as recommended by the RC at its September 21, 2021 meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

The motion to recommend Participants Committee support was unanimously approved.

Summary of ISO New England Board and Committee Meetings
October 7, 2021 Participants Committee Meeting

Since the last update, the Compensation and Human Resources Committee, the Markets Committee, the System Planning and Reliability Committee, and the Information Technology and Cyber Security Committee met on September 22. On September 23, the Nominating and Governance Committee, and the Board of Directors met. All of the meetings were held by videoconference.

The Compensation and Human Resources Committee reviewed details regarding the employee health and benefit plan renewals for 2022. The Committee also examined national compensation survey data regarding projected merit and promotional increase budgets. After reviewing information specific to the utility industry, all-industry data, and data from other system operators, the Committee approved a 3.0% merit increase and a 0.5% promotional/equity increase for inclusion in the proposed 2022 operating budget. Next, the Committee reviewed proposed conforming edits to its charter regarding previously approved changes in the Company's retirement and welfare plan investment fiduciary; the Committee agreed to recommend a revised charter for the Board's approval in November. Management updated the Committee on the Company's return to campus plans. During executive session, the Committee discussed director compensation trends with the Company's compensation consultant.

The Markets Committee received an update on various market issues, including the initiative to eliminate the Minimum Offer Price Rule, and the investment environment for renewable resources in New England. The Committee also conducted its annual discussion of the External Market Monitor's (EMM's) business continuity and succession plans and held an executive session with the EMM. Following the executive session, the System Planning and Reliability Committee joined the meeting to consider the key risks within the scope of both Committees' oversight. The Committees discussed the risks that are a function of market activity, technological change, and regulatory changes that are relevant to both Committees. The Committees agreed that significant risks exist for the foreseeable future, driven by the inherent complexity of wholesale electricity markets, the inter-relationship between planning, markets and operations, the increasing urgency from stakeholders to pursue various topics simultaneously, state and federal priorities, and regulatory uncertainty.

The System Planning and Reliability Committee reviewed the schedule for the 2021 Regional System Plan public meeting and discussed comments received from stakeholders on the Plan. The Committee was provided with a status update of Regional System Plan projects. The Committee discussed the states' transmission planning recommendations in NESCOE's June 2021 Report to the Governors, and noted the Company's progress in this area. The Committee then reviewed a summary of the FERC Advance Notice of Proposed Rulemaking on transmission and interconnection reforms and potential responses from the Company. Following a brief executive session, the Committee joined the Markets Committee meeting to consider the key risks within the scope of both Committees' oversight (see above).

The Information Technology and Cyber Security Committee convened with the full Board for the Committee's annual "deep dive" on cyber security issues and received a presentation from an expert on ransomware attacks, proactive exercises to minimize the risk of an attack, and the process for data recovery in the event of an attack. The Committee also discussed the Company's communications plan in the event of a cyber security event and progress related to the cyber security work plan.

The Nominating and Governance Committee adopted resolutions recommending that the Board elect the proposed slate of directors. The Committee discussed the launch of the Joint Nominating Committee process for 2022, and also discussed Board needs and requisite skills in connection with the Company's annual board succession process. Next, the Committee conducted its annual assessment of the risks within the Committee's purview. The Committee also received an update on the political environment, including related state and federal topics, and discussed significant energy legislation and policies considered by federal and state policymakers this year. The Committee then conducted its biennial consideration of its charter. The Committee reviewed its charter, confirmed its compliance, and agreed to revise it to emphasize the Committee's focus on diversity on the Board.

The Board of Directors held its annual meeting on September 23. Acting as the members of the Corporation, the Board elected Ms. Anders and Messrs. Corneli and Curran as Directors for three-year terms, and Ms. Flax as Director for a four-year term. The Board also approved changes to the Company's Articles of Incorporation, waived the provisions of the Bylaws, and approved a Waiver Agreement regarding the Participants Agreement, all in order to elect an eleventh director and a single director with a four-year term.

The Board also elected Ms. LaFleur as Chair of the Board of Directors, and adopted the committee assignments recommended by the Nominating and Governance Committee, as follows:

- Ms. Flax and Messrs. Curran and Corneli shall serve on the **Audit and Finance Committee**, with Mr. Curran to serve as Chair;
- Mses. Anders, LaFleur, and VanZandt and Mr. Denis shall serve on the **Compensation and Human Resources Committee**, with Mr. Denis to serve as Chair;
- Ms. VanZandt and Messrs. Colangelo, Curran, and Vannoy shall serve on the **Information Technology and Cyber Security** Committee, with Mr. Vannoy to serve as Chair;
- Mses. Anders and VanZandt and Messrs. Colangelo, Corneli, Curran, Denis, and Vannoy shall serve on the **Joint Nominating Committee**, with Mr. Colangelo to serve as Chair;
- Ms. Flax and Messrs. Corneli, Curran, Rush, and Vannoy shall serve on the **Markets Committee**, with Mr. Rush to serve as Chair;
- Ms. LaFleur and Messrs. Colangelo, Rush, and Vannoy shall serve on the **Nominating and Governance Committee**, with Mr. Colangelo to serve as Chair; and
- Mses. Anders and VanZandt and Messrs. Colangelo and Denis shall serve on the **System Planning and Reliability Committee**, with Ms. VanZandt to serve as Chair.

The Board also elected the Company's officers for the upcoming year, reviewed assignments of directors as liaisons to individual states, and recognized retiring directors Kathleen Abernathy and Phil Shapiro, thanking them for their service on the Board.

The Board received a report from the CEO, including an update on corporate goal achievement and a discussion of plans to return to the office. Next, the Board discussed the 2022 budgets. The Board reviewed the states' comments on the budgets and discussed the remaining stakeholder process, noting that the Board's vote on the budgets will take place after the Board is notified of feedback from and the vote of the NEPOOL Participants Committee.

The Board then prepared for its upcoming meeting with NESCOE, received reports from the standing committees, and considered potential topics for the meetings scheduled in November with NEPOOL and NECPUC. The Board met with NESCOE and reviewed slides that have been posted at https://www.iso-ne.com/static-assets/documents/2021/09/iso-ne-response_to_states-vision_sept_23_2021.pdf.

Response to the New England States' Vision Statement and Advancing the Vision Report

Meeting with New England States

ISO New England Board of Directors

Introduction

- The ISO Board of Directors has directed management to prioritize transmission planning studies and market pathways analysis in support of the states' clean energy vision
- The board is also pursuing targeted governance and communications enhancements, consistent with its independence and oversight role and with the need to focus on transmission and market priorities
- The board remains committed to working with the states and NEPOOL to achieve the region's goals for a clean energy system that is reliable and efficient

Our Commitment to the Clean Energy Transition Is Explicitly Included in Our Vision Statement

Mission: *What we do*

Through collaboration and innovation,
ISO New England plans the transmission system,
administers the region's wholesale markets, and
operates the power system to ensure reliable and
competitively priced wholesale electricity

Vision: *Where we're going*

To harness the power of competition and advanced
technologies to reliably plan and operate the grid
as the region transitions to clean energy

*The ISO's **Vision** for the future represents our long-term intent and guides the formulation of our Strategic Goals.*

ISO Plays a Unique Role in the Region

Independence

- The independent role of the ISO was central to the creation of competitive wholesale electricity markets and planning the bulk electric transmission system in New England

Filing Market Rules with FERC

- Granting the ISO primary responsibility to file market rules with FERC was central to the Commission's vision for the ISO becoming a Regional Transmission Organization, and remains a key aspect of the ISO's independence

ISO Plays a Unique Role in the Region, cont.

Transmission for Reliability

- The ISO has primary responsibility for identifying reliability needs and approving the projects in the transmission plan for the region
  - The board votes on the Transmission Project List in the Regional System Plan, following input from stakeholders and the states through the Planning Advisory Committee

Transmission for Public Policy

- The ISO tariff has provisions to enable transmission planning for public policy
  - The *states play a key role* in determining whether studies are needed, but to date, have not exercised the need for such studies
- The states' Vision foresees large-scale transmission investment to enable clean energy
  - This will require *increasing levels of input and decision-making from state regulators and policymakers* with the ISO playing a technical role to support the states

States and ISO Have Overlapping Objectives

- The states have **clean-energy mandates** – and we are supportive of the states in those efforts
- The ISO has a **reliability mandate** and a **mandate to administer competitive wholesale markets** for the resources needed for a reliable system – and we know that the states recognize the importance of reliability and have continued to express support for competitive markets
- There is an overarching need to ensure a reliable power system throughout the clean energy transition

ACTIVITIES TO FURTHER THE STATES' VISION

ISO Board and Management are committed to working with the states to achieve a reliable and efficient clean energy future for New England

ISO New England Is Aligned with the States on the Clean Energy Transition

Transmission Planning

- 2050 Transmission Study
- Cluster Studies to Interconnect Offshore Wind on Cape Cod
- Transition Planning for the Clean Energy Transition – Pilot Study
- Future Grid Reliability Study
- Storage as a Transmission Solution

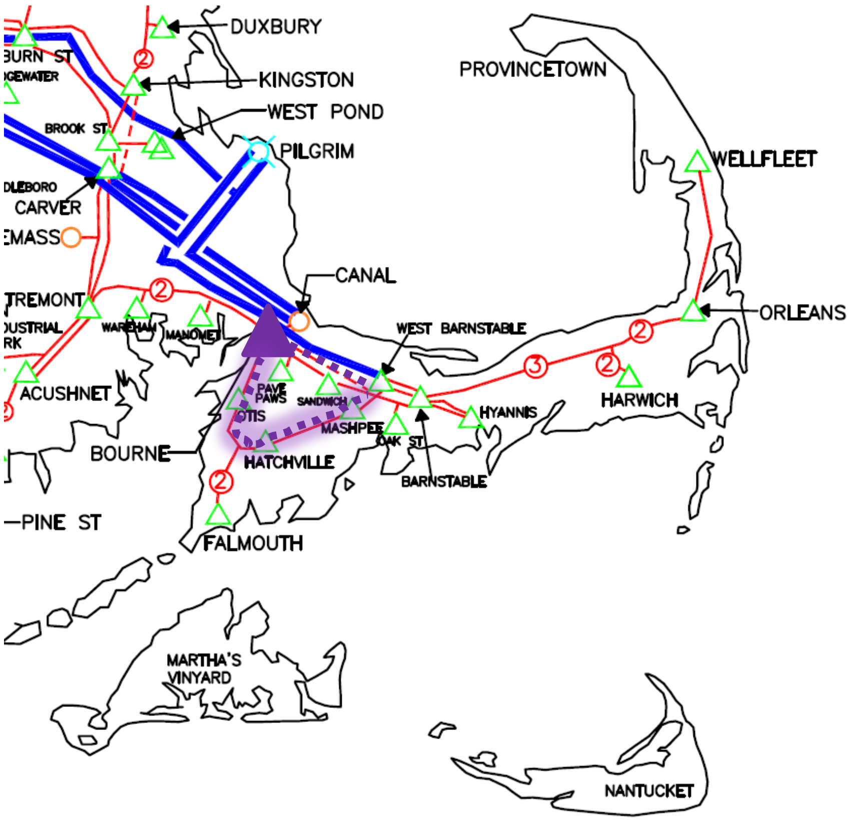
Wholesale Market Design

- Pathways analysis of a forward clean energy market and net carbon pricing, and a hybrid of the two concepts
- Elimination of the Minimum Offer Price Rule (MOPR)
- Revisit ancillary service design
- Enable distributed energy resource aggregations to participate in the wholesale market (Order 2222)

2050 Transmission Study Is a Direct Response to the States' 2020 Vision Statement

- At the states' request, the ISO is leading a high-level transmission study to look at scenarios to **reliably and cost-effectively incorporate clean energy and distributed energy resources by 2050**
  - This is referred to as the "2050 Transmission Study"
    - Primary focus is the year 2050, but also looking at 2035 and 2040
  - Study is intended to look beyond the current, 10-year planning horizon
  - The ISO is working with NESCOE to develop study assumptions and the study scope; further discussions with stakeholders will take place at the Planning Advisory Committee
  - Study will include high-level cost estimates to help the states evaluate different transmission scenarios
  - The ISO is working with NESCOE to draft corresponding changes to the ISO tariff to enable this type of transmission study on a recurring basis

The ISO Initiated the Cape Cod Resource Integration Study to Increase Integration of Offshore Wind



- 1,600 MW of offshore wind on Cape Cod have completed System Impact Studies and can interconnect immediately
- 3,260 MW of additional generation are seeking to interconnect on the Cape
  - Previous studies by the ISO have identified that without transmission upgrades the ability to interconnect offshore wind is limited
- The ISO initiated the Cape Cod Resource Integration Study (CCRIS) to identify infrastructure upgrades to enable the interconnection of approximately 1,200 MW of additional offshore wind
  - The ISO has initiated a second CCRIS to support the interconnection of additional wind

Other Planning Initiatives

- **Transmission Planning for the Clean Energy Transition**
  - The ISO is conducting a pilot study to proactively plan for growing levels of Distributed Energy Resources (DERs), renewable resources, including offshore wind, imports via HVDC transmission interconnections, and energy storage
    - Study will aid in developing assumptions for use in future Needs Assessments, and will explore reliability concerns that may arise
    - Focus is the current, 10-year planning horizon for reliability needs
    - The ISO presented initial results in summer 2021; further results are coming this fall
- **Future Grid Reliability Study**
  - The ISO is conducting a study of how the power system could operate in **2040** under current energy and environmental policies
    - NEPOOL requested the study; stakeholders, including NESCOE, developed the scenarios
    - The ISO presented initial results in June; further results are coming this fall
    - Using 2040 aligns with interim years in the 2050 Transmission Study
- **Storage as a Transmission Solution**
  - Beginning in Q1 2022, the ISO will initiate discussions of proposed tariff changes to consider storage as a transmission asset for the purposes of implementing solutions to Needs Assessments or Public Policy Transmission Studies

Market Design for the Clean Energy Future

- **Analysis of Pathways to a Future Grid**
  - The ISO is working with regional stakeholders to evaluate potential wholesale market frameworks that reflect states' policies
    - Analysis includes a regional net carbon price, a Forward Clean Energy Market, and a hybrid of the two concepts
  - Study results are expected in Q2 2022
- **Elimination of the MOPR**
  - The ISO is developing a proposal with input from stakeholders to address the dual objectives of allowing sponsored resources to clear and maintaining competitive capacity pricing that can attract merchant entry when needed to maintain resource adequacy
- **Ancillary Service Markets**
  - With the evolving power system, it will be necessary to enhance ancillary services to ensure the markets produce a reliable next-day operating plan
  - In 2022, the ISO will be refocusing efforts on proposals to co-optimize reserves in the day-ahead energy markets

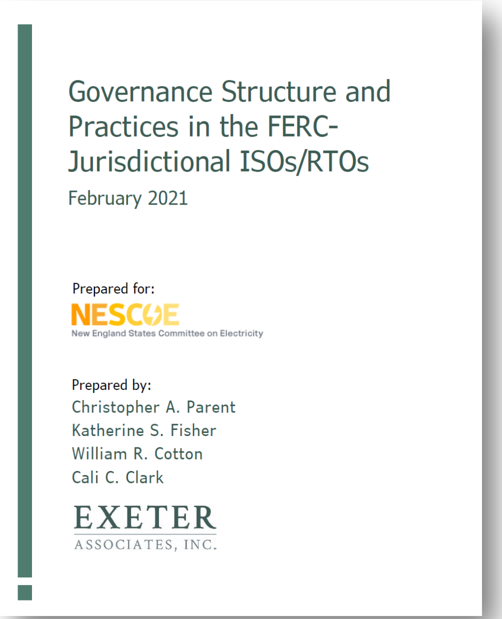
Market Design for the Clean Energy Future, cont.

- **Integration of Distributed Energy Resource Aggregations (DERAs)**
  - The ISO plans to file its proposal with FERC in February 2022 to integrate DERAs into the wholesale markets, pursuant to Order 2222

- **Enhancements to Resource Capacity Accreditation (RCA)**
  - To assist with ensuring a reliable and clean energy future, the ISO is working with the states and NEPOOL to improve the methodology for determining resource capacity ratings in order to reflect the evolving resource mix

ISO-NE Board Review of Governance Practices

- The states' review of ISO/RTO governance practices reflects that ISO-NE is comparable to peer organizations
- The Nominating & Governance Committee and the board of directors have reviewed current practices in light of the states' recommendations, have met with the states, and are making changes that are consistent with the ISO's core requirement for *independence* and its role as an *oversight board,* and that can be achieved without impeding the organization's focus on the states' markets and transmission goals


Governance Structure and Practices in the FERC-Jurisdictional ISOs/RTOs
February 2021

Prepared for:
NESCOE
New England States Committee on Electricity

Prepared by:
Christopher A. Parent
Katherine S. Fisher
William R. Cotton
Cali C. Clark
EXETER
ASSOCIATES, INC.

Annual Open Meeting of the Board

- The board of directors will hold an annual open meeting:
  - The meeting will be focused on the wholesale electricity markets, in even-numbered years beginning in 2022
  - The meeting will be focused on system planning, in odd-numbered years beginning in 2023
    - Potentially linked to the biennial Regional System Plan public meeting
  - *This would be in addition to meetings the board holds with the states and NEPOOL sectors throughout the year*

Board Committee Charter Revisions

- The Board Markets Committee and System Planning and Reliability Committee have updated their charters to ensure that the committees' work is conducted consistent with the ISO's Vision, which emphasizes the company's role in utilizing competitive markets and planning processes, and advanced technologies, to facilitate a reliable transition to clean energy (*Committee charters are posted on the ISO web*)
- The board of directors and committees do evaluate costs and consumer impact in discussions on ISO proposals and, as the next section explains, the board looks forward to having further conversations with the states on this topic

Enhancements to Board Communications

- Distribute the CEO’s monthly board reports directly to the states
  - ISO staff can look for areas to enhance summaries
  - States also have opportunities to ask questions of the CEO about board activities at monthly NEPOOL Participants Committee meetings
- Additional board discussions with the states
  - The board proposes to add plenary or liaison meetings where necessary to discuss consumer implications of an ISO proposal
  - If the states have a majority position on an ISO proposal, the board is willing to meet with the states to discuss their position, and management will include consideration of a state majority position in filings to FERC

Leadership Role for the New England States on a Regional Clean Energy Market Design

- The ISO's analysis of Pathways to a Future Grid is targeted for completion in April 2022
- Should the Pathways results lead to consensus from the states on a viable option, we will look to state regulators and policymakers to provide increasing levels of input and decision-making to establish a clean energy market

Enhancing Communication of Technical Information to Non-Technical Audiences

- Existing communications seek to deliver technical information to technical as well as non-technical audiences, such as:
  - Regional Electricity Outlook (the “REO”)
  - ISO Newswire
  - ISO-to-Go mobile app
  - ISO Express data portal
  - State and regional profiles
  - Regional System Plan: executive summary and public meeting
  - Consumer Liaison Group: presentations, summaries, annual report
  - ISO101 Online and special session for public officials
- Management can also meet with the states to review existing documents to identify additional reasonable needs for enhanced communications with non-technical audiences

Equity and Environmental Justice

- The board and management understand this is an important issue and offer to be a resource to the states on matters related to the regional power system as they evaluate equity and environmental justice issues
- External Affairs is available to be the initial point of contact

Conclusion

- ISO New England, the New England states and regional stakeholders have **a long history of collaboration** to ensure the region has a reliable transmission system, a comprehensive system planning process, and wholesale electricity markets that are consumer-focused, competitive and deliver the electricity the region needs today and in the future
- The board's role is to **provide advice** to **and oversight** of management, including to ensure they have the right talent and resources needed to fulfill the organization's mission and vision
- We believe the ISO is **well positioned to support the clean energy transition** and we look forward to continuing to work with the states, NEPOOL and other stakeholders on this endeavor

NEPOOL Participants Committee Report

October 2021

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

Regular Operations Report - Highlights

Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Update: August 2021 Energy Market value totaled $685M
  - September 2021 Energy market value was $497M, down $188M from August 2021 and up $290M from September 2020
  - September 2021 natural gas prices over the period were 12% higher than for August
    - Average RT Hub Locational Marginal Prices ($46.48/MWh) over the period were 5% lower than August averages
      - DA Hub: $48.01/MWh
    - Average September 2021 natural gas prices and RT Hub LMPs over the period were up 206% and up 134%, respectively, from September 2020 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 99.9% during September, down from 100.5% during August*
    - The minimum value for the month was 92.7% on Wednesday, September 1st

All data through September 29th

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

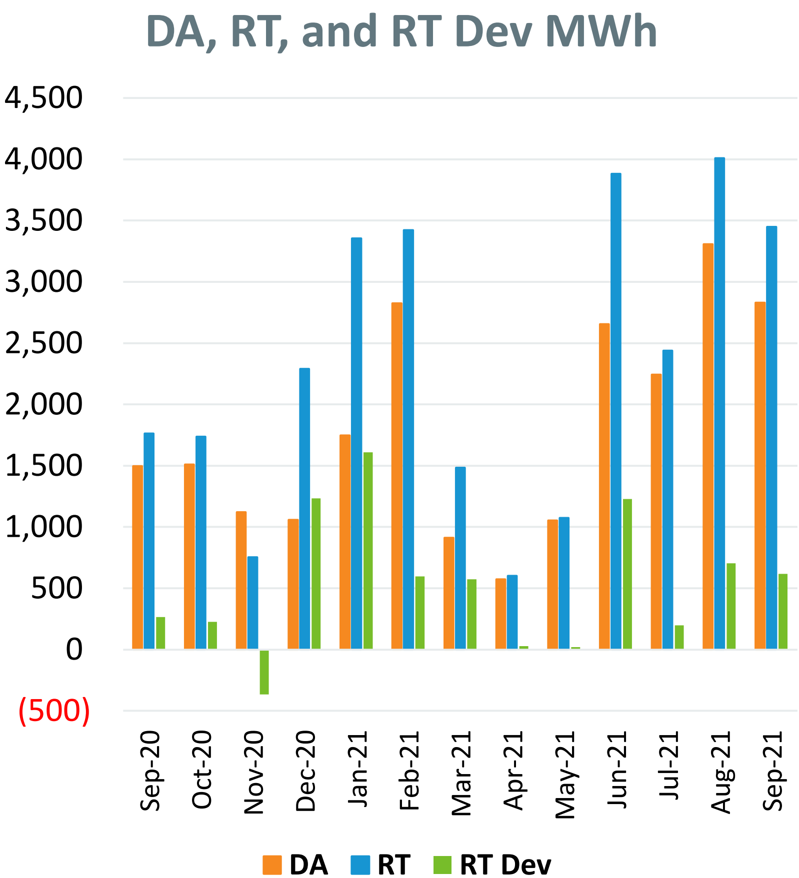
Underlying natural gas data furnished by: ice Global markets in clear view

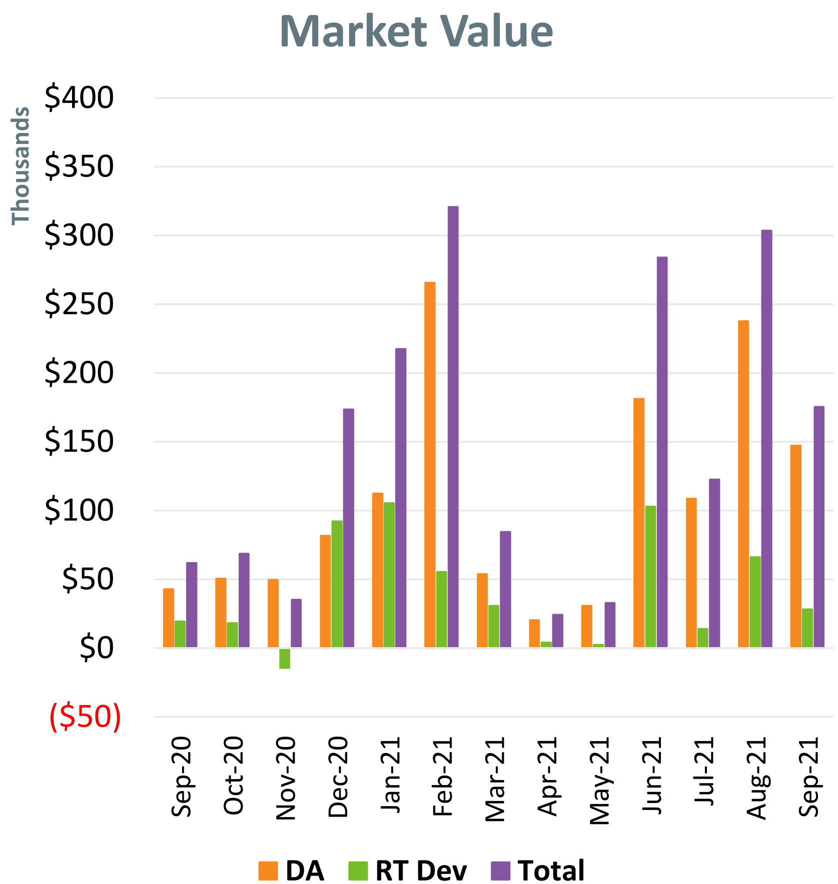
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - September 2021 NCPC payments totaled $1.3M over the period, down $2M from August 2021 and down $1.1M from September 2020
    - First Contingency payments totaled $1.3M, down $1.5M from August
      - $1.3M paid to internal resources, down $1.5M from August
        - » $350K charged to DALO, $491K to RT Deviations, $445K to RTLO*
      - $42K paid to resources at external locations, down $1K from August
        - » $38K charged to DALO at external locations, $1K to RT Deviations
    - Second Contingency payments totaled $5K, down $93K from August
    - Voltage and Distribution payments were negligible ($3K combined)
  - NCPC payments over the period as percent of Energy Market value were 0.3%

* NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $263K; Rapid Response Pricing (RRP) Opportunity Cost - $170K; Posturing - $12K; Generator Performance Auditing (GPA) - $0K

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

- Production cost preliminary results for the 2021 Economic Study (Future Grid Reliability Study) were discussed at a special September 17 PAC meeting and joint MC/RC meetings
  - The ISO is working on refining the scenario matrix and will present to the MC/RC for approval before completing the final runs
- RC voted in favor of the FCA 16 ICR and Related Values at their September 21 meeting; FERC filing to be made by November 9
- 2022 ARA assumption discussions continue at the PSPC
- Regional System Plan Public Meeting will be held virtually on October 6
- Four Attachment K revisions are in various stages of development

Forward Capacity Market (FCM) Highlights

- CCP 12 (2021-2022)
  - Third and final annual reconfiguration auction (ARA3) was held on March 1-3, and results were posted on March 29
- CCP 13 (2022-2023)
  - Second annual reconfiguration auction (ARA2) was held on August 2-4, and results were posted on August 31
  - Development of ICR-Related Values continues with discussions at the PSPC; FERC filing to be made by November 30
- CCP 14 (2023-2024)
  - First annual reconfiguration auction (ARA1) was held on June 1-3, and results were posted June 30
  - Development of ICR-Related Values continues with discussions at the PSPC; FERC filing to be made by November 30
- CCP 15 (2024-2025)
  - Auction results were filed with FERC on February 26 and FERC approved on June 24
  - Development of ICR-Related Values continues with discussions at the PSPC; FERC filing to be made by November 30

CCP – Capacity Commitment Period

FCM Highlights, cont.

- CCP 16 (2025-2026)
  - FCA 16 will model the same zones as FCA 15
    - Export-constrained zones: Northern New England, and Maine nested inside Northern New England
    - Import-constrained zones: Southeast New England
  - A summary of permanent and retirement de-list bids was posted on March 17, and a summary of substitution auction demand bids was posted on April 30
    - These summaries were reposted on June 11 to reflect de-list bid withdrawals made after the Internal Market Monitor reissued its determinations based on the FERC-accepted CONE, Net CONE and Capacity Performance Payment Rate for FCA 16
      - The bid withdrawal Tariff provision that FERC accepted was for FCA 16 only
    - New Capacity Qualification is ongoing
  - ICR and Related Values to be filed no later than November 9, 2021

CONE – Cost of New Entry

Load Forecast

- Efforts continue to enhance load forecast models and tools to improve day-ahead and long-term load forecast performance
- Efforts to expand/improve the transportation electrification forecast for CELT 2022 have commenced
  - Initial discussion related to these efforts was at the September 24 Load Forecast Committee meeting

FERC Order 1000

- Qualified Transmission Project Sponsor (QTPS)
  - 25 companies have achieved QTPS status
- Competitive Solution Process: Order 1000/Boston 2028 Request for Proposal Lessons Learned
  - The ISO held discussions on the associated Tariff changes at the 7/14/21, 8/24/21, and 9/28/21 TC meetings
  - The first discussion at the RC occurred on 9/21/21; next discussion is scheduled for 10/19/21

Highlights

- The lowest 50/50 and 90/10 Fall Operable Capacity Margins are projected for week beginning October 16, 2021.

- The lowest 50/50 and 90/10 Preliminary Winter Operable Capacity Margins are projected for week beginning January 8, 2022.

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (4.0°F) Max: 86°F, Min: 52°F Precipitation: 7.47" – Above Normal Normal: 3.56"	Hartford	Temperature: Above Normal (1.3°F) Max: 86°F, Min: 44°F Precipitation: 6.81" - Above Normal Normal: 4.39"

Peak Load:	19,707 MW	September 15, 2021	18:00 (ending)

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

Procedure	Declared	Cancelled	Note
None in September, 2021			

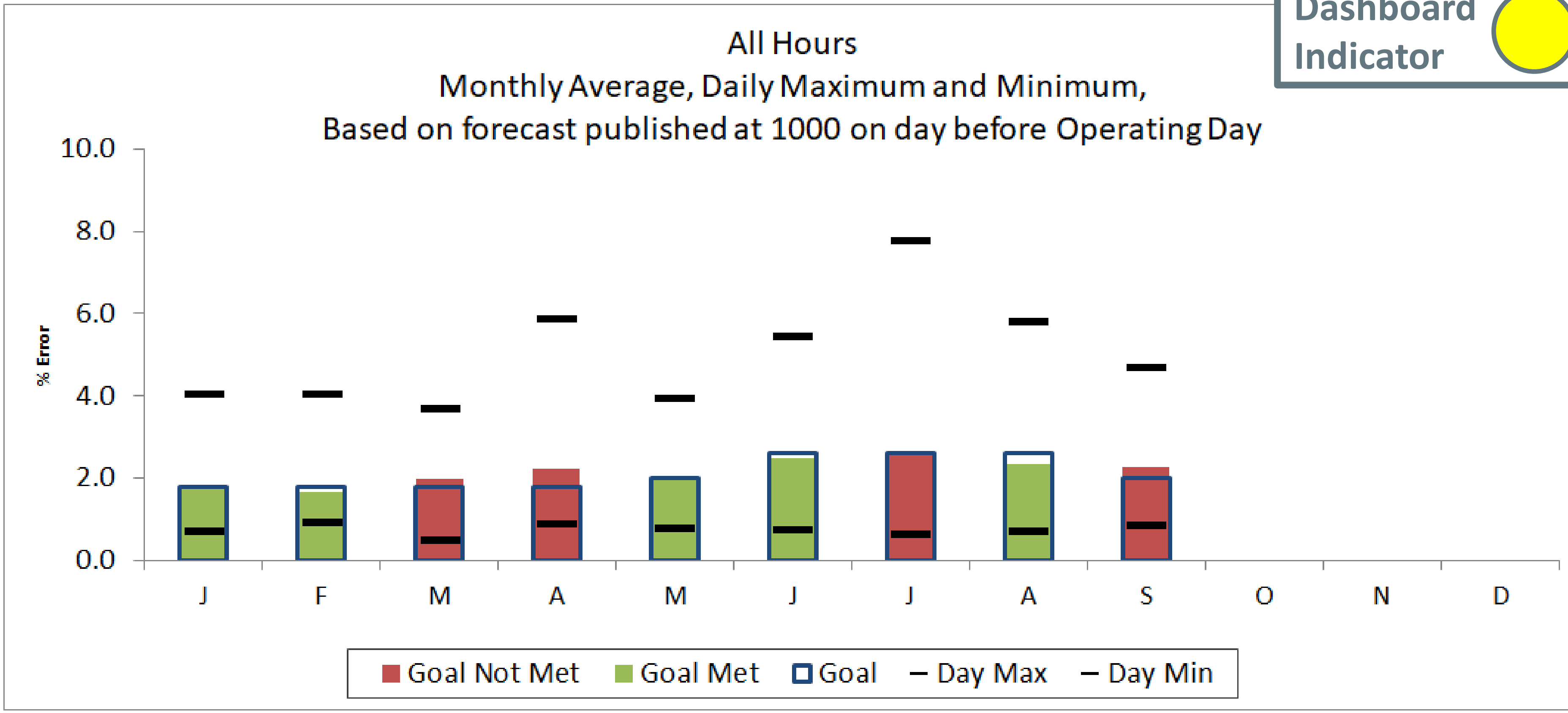
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
9/27/2021	PJM	750
9/30/2021	IESO	530

2021 System Operations - Load Forecast Accuracy

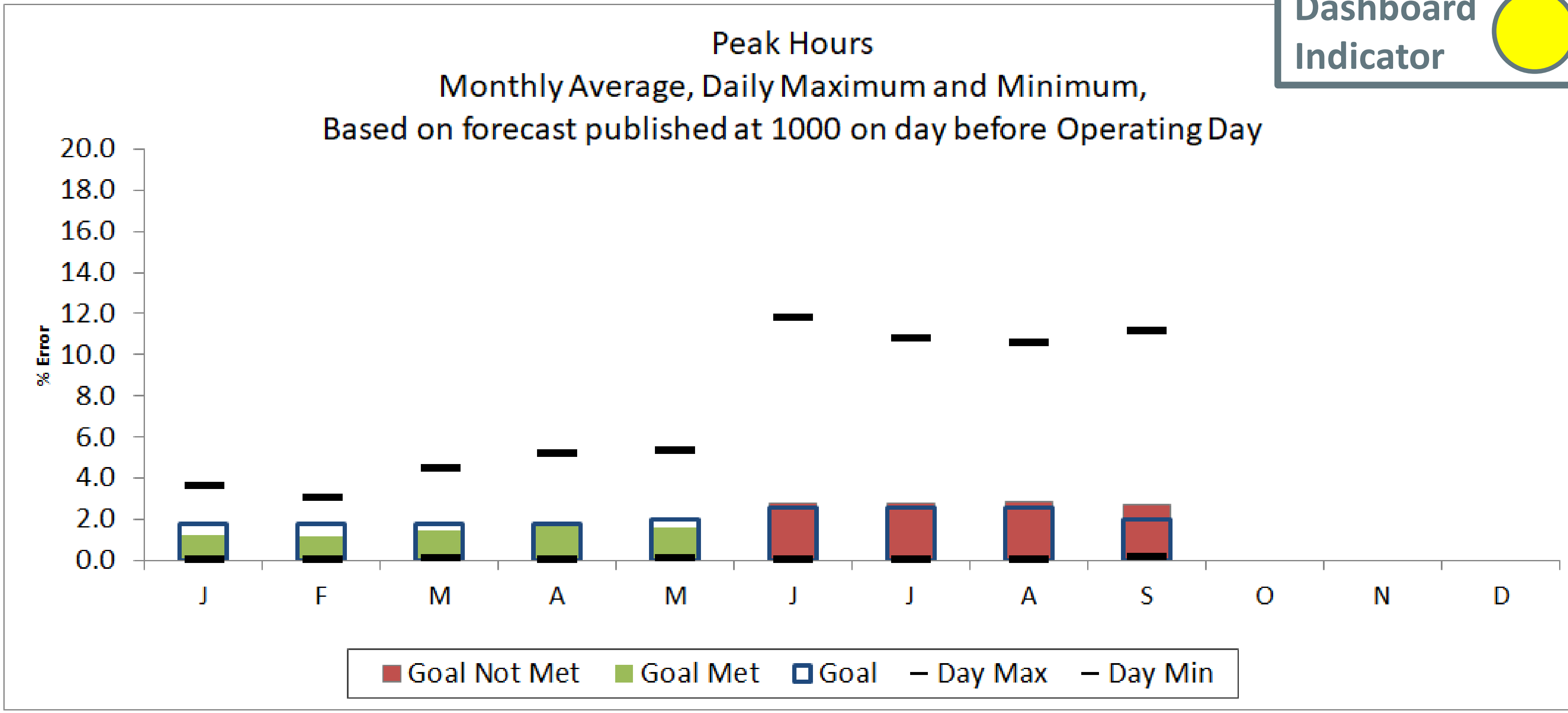
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.04	4.03	3.67	5.85	3.92	5.41	7.75	5.77	4.68				7.75
Day Min	0.70	0.92	0.49	0.88	0.77	0.73	0.63	0.71	0.86				0.49
MAPE	1.72	1.66	1.97	2.24	1.95	2.50	2.61	2.33	2.28				2.14
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00				

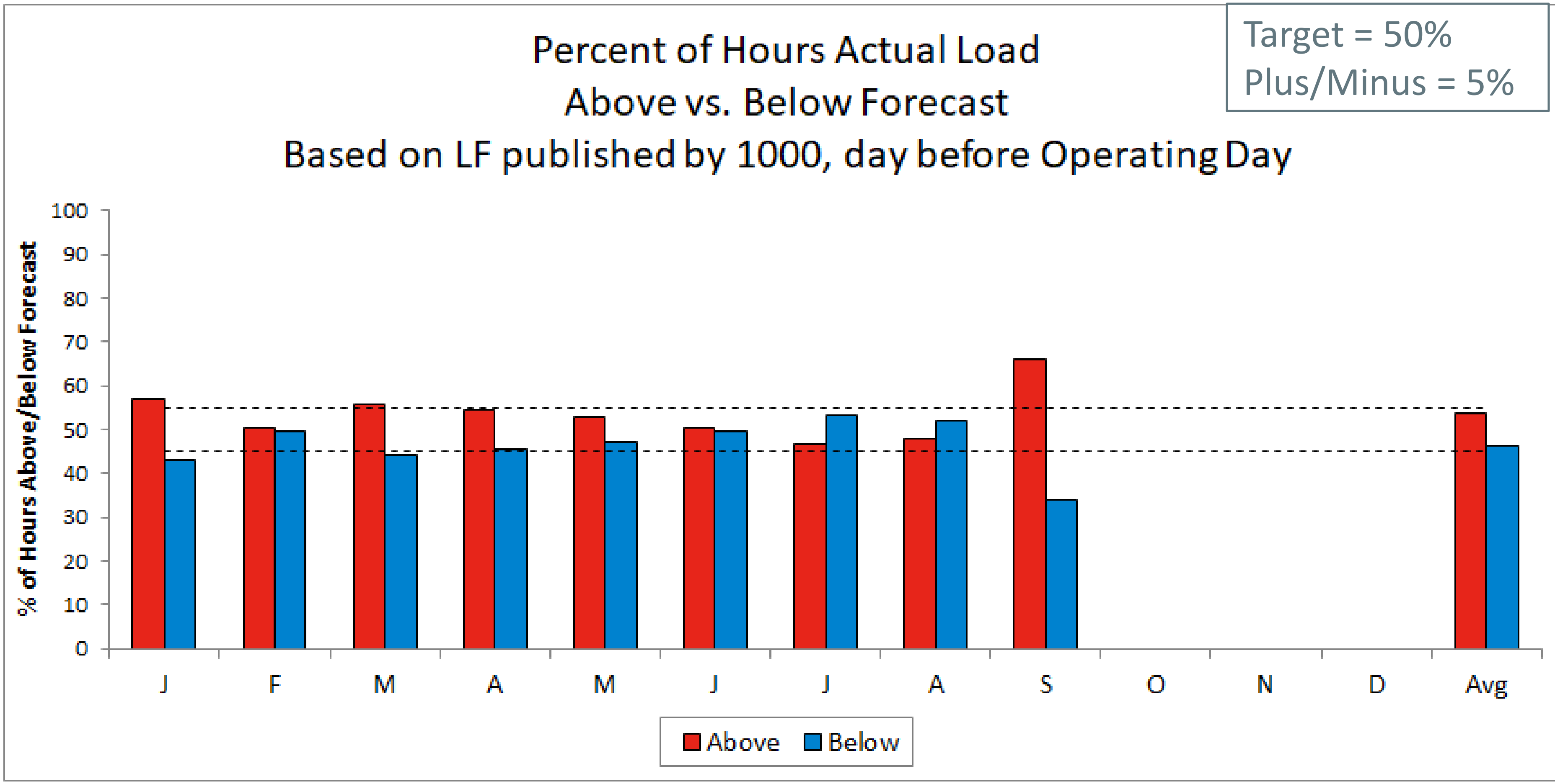
2021 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



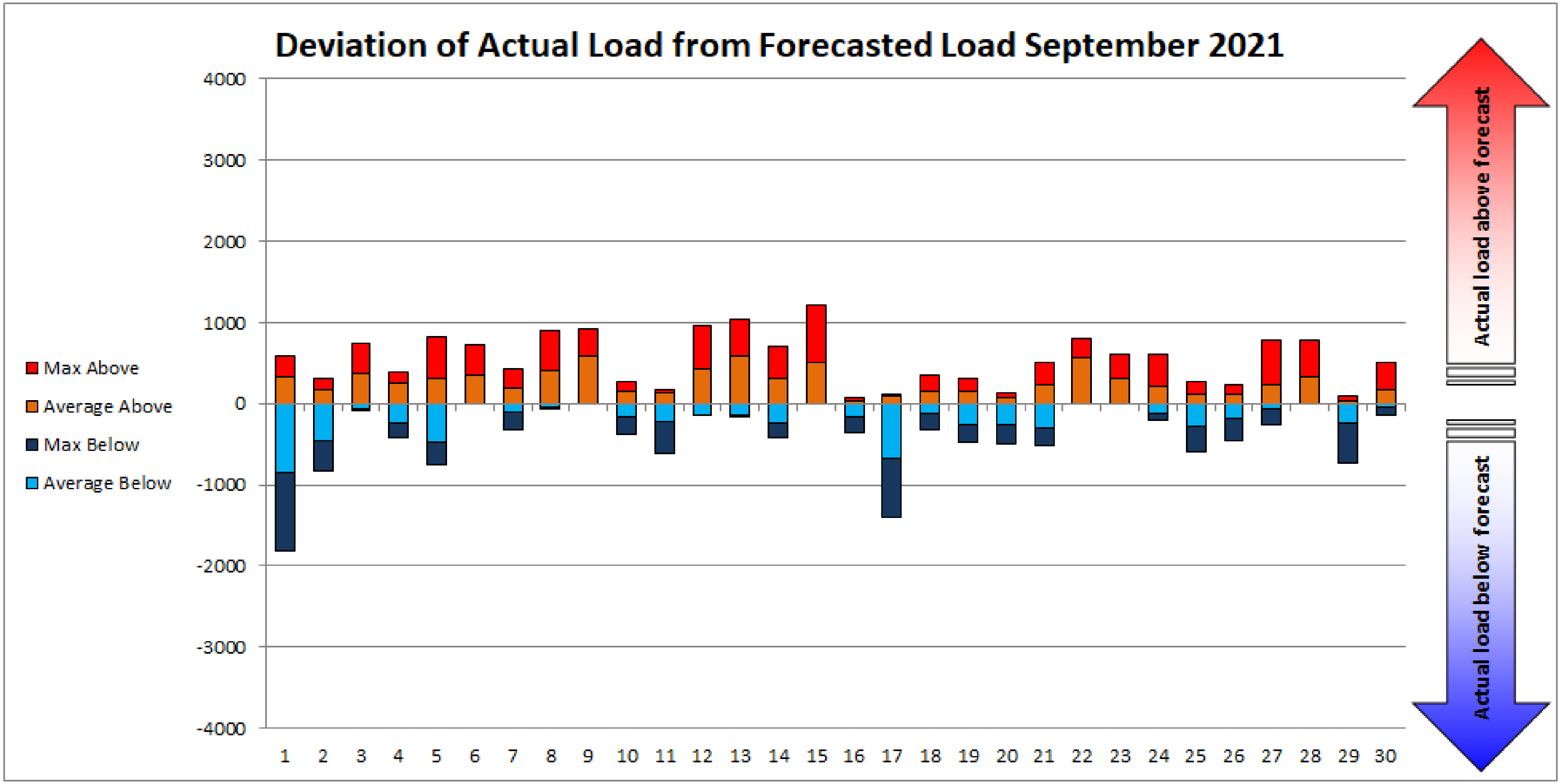
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	3.61	3.03	4.47	5.19	5.31	11.76	10.75	10.54	11.13				11.76
Day Min	0.02	0.06	0.08	0.03	0.11	0.04	0.05	0.01	0.17				0.01
MAPE	1.26	1.18	1.48	1.66	1.60	2.79	2.78	2.86	2.73				2.04
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00				

2021 System Operations - Load Forecast Accuracy cont.

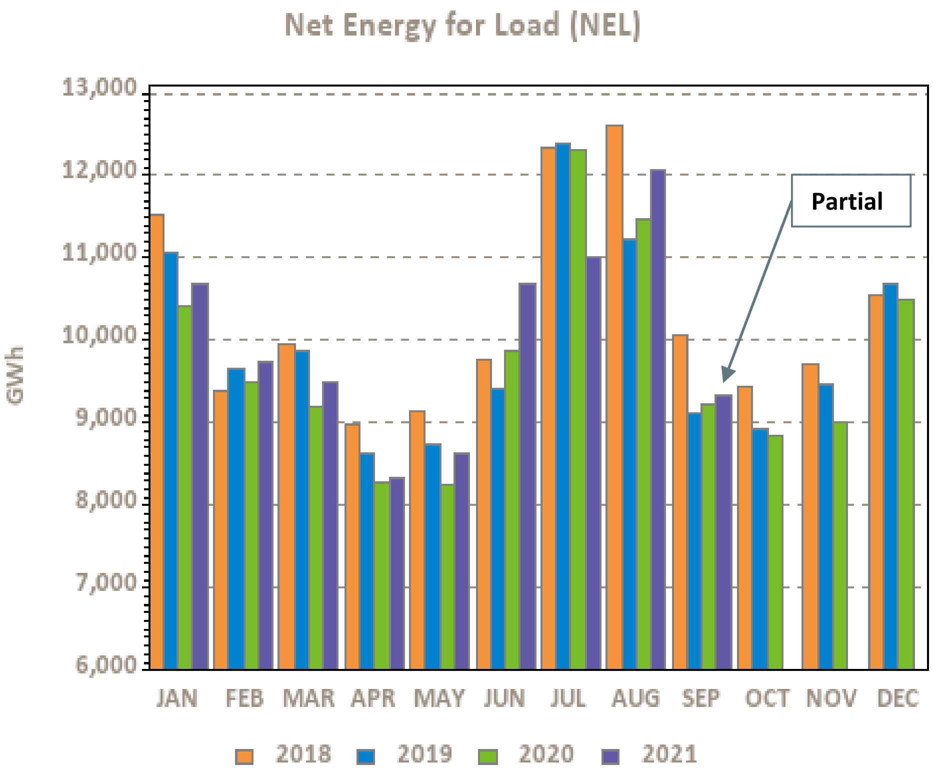


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	57.1	50.4	55.6	54.4	52.8	50.3	46.9	47.8	66.2				53
Below %	42.9	49.6	44.4	45.6	47.2	49.7	53.1	52.2	33.8				47
Avg Above	209.5	166.7	185.4	206.1	227.4	233.1	214.5	227	263.1				263
Avg Below	-147.6	-216.4	-188.0	-167.9	-146.8	-309.1	-348.1	-307.5	-195.6				-348
Avg All	60	-25	30	40	61	-48	-122	-79	105				3

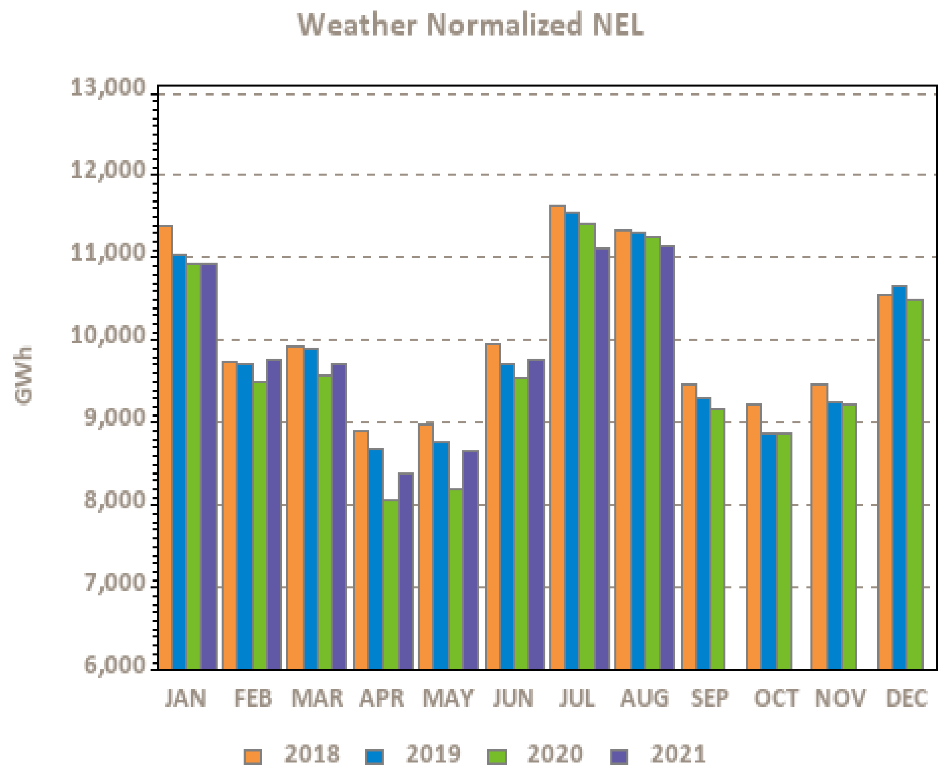
2021 System Operations - Load Forecast Accuracy cont.



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



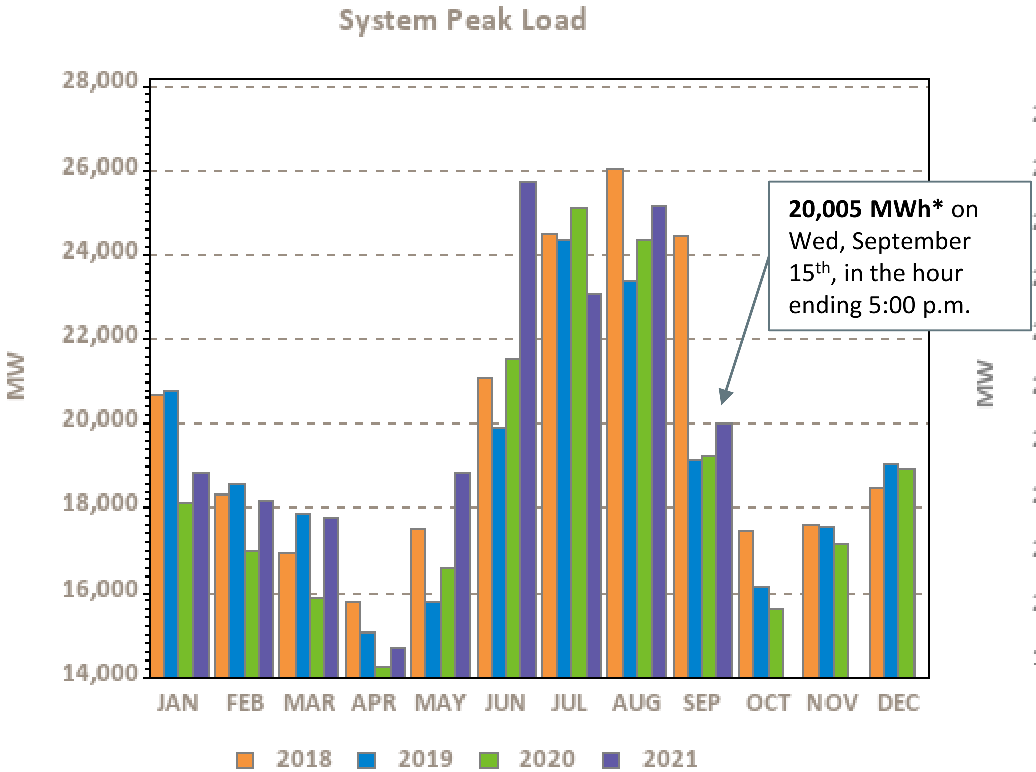
Ann Tot (TWh): 123.5 119.2 116.9 90.0



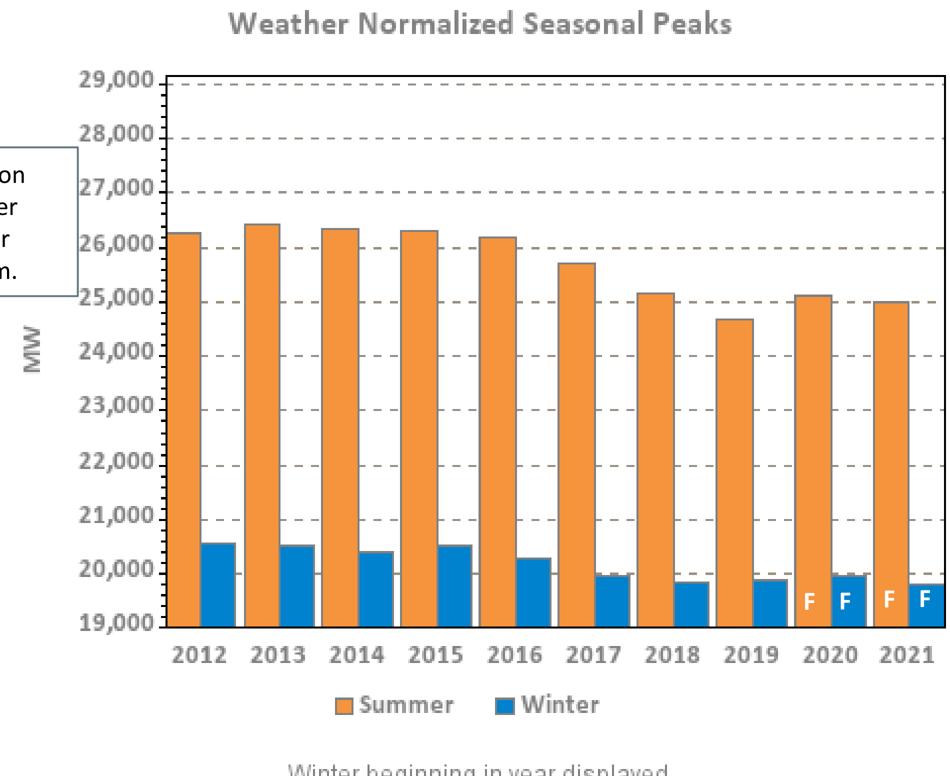
Ann Tot (TWh): 120.6 118.8 116.3 79.5

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 is typically reported on a one-month lag.

Monthly Peak Loads and Weather Normalized Seasonal Peak History



*Revenue quality metered value

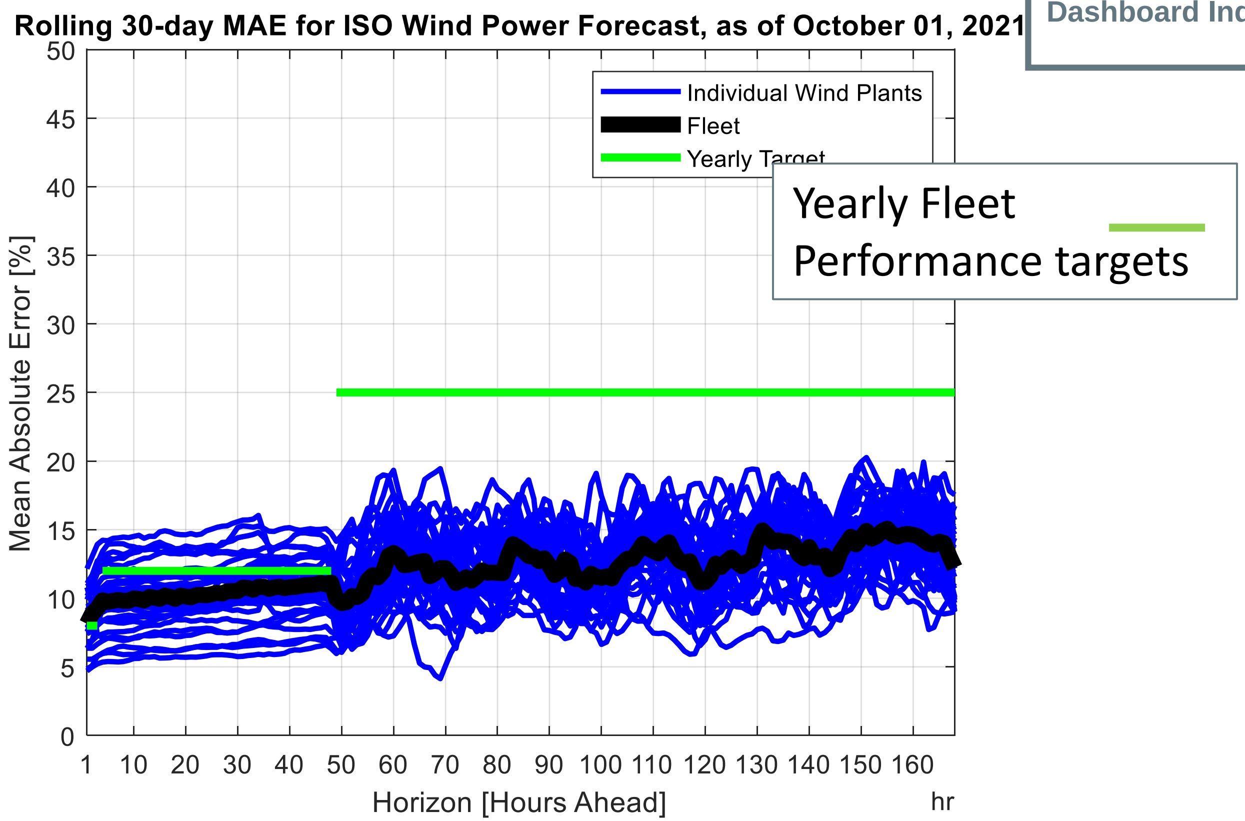


Winter beginning in year displayed

F – designates forecasted values, which are typically 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

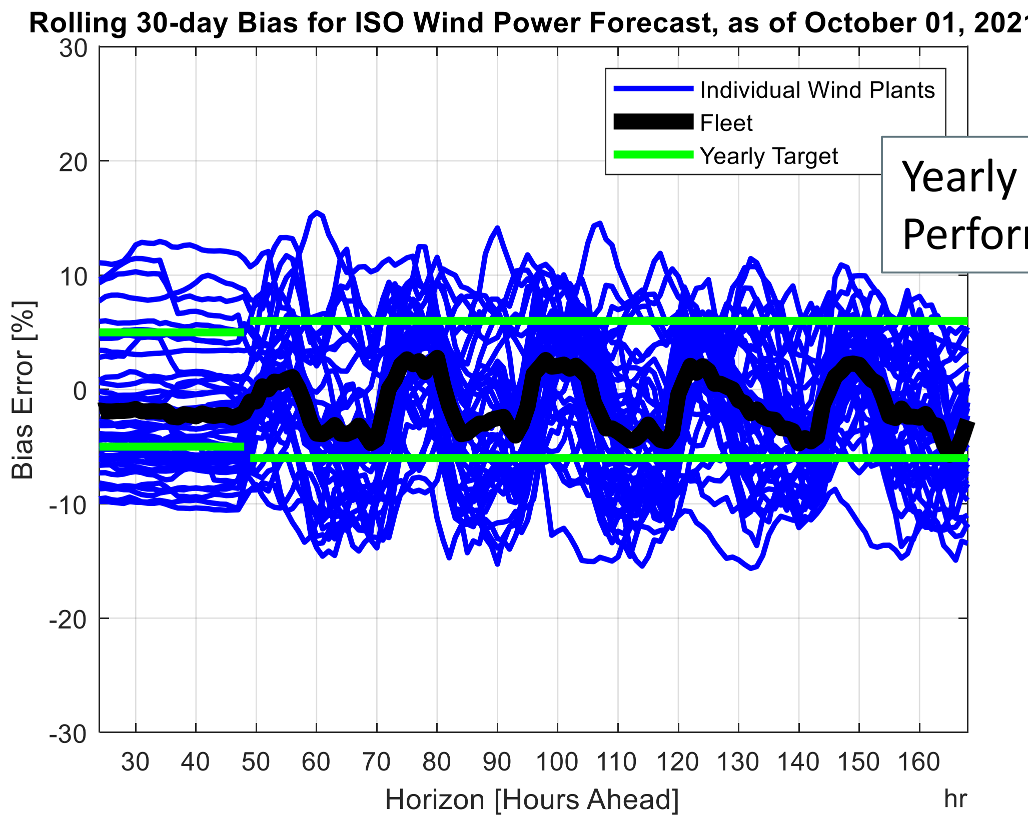
Dashboard Indicator



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 forecast is very good compared to industry standards, and monthly MAE is within the yearly performance targets.

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

Dashboard Indicator

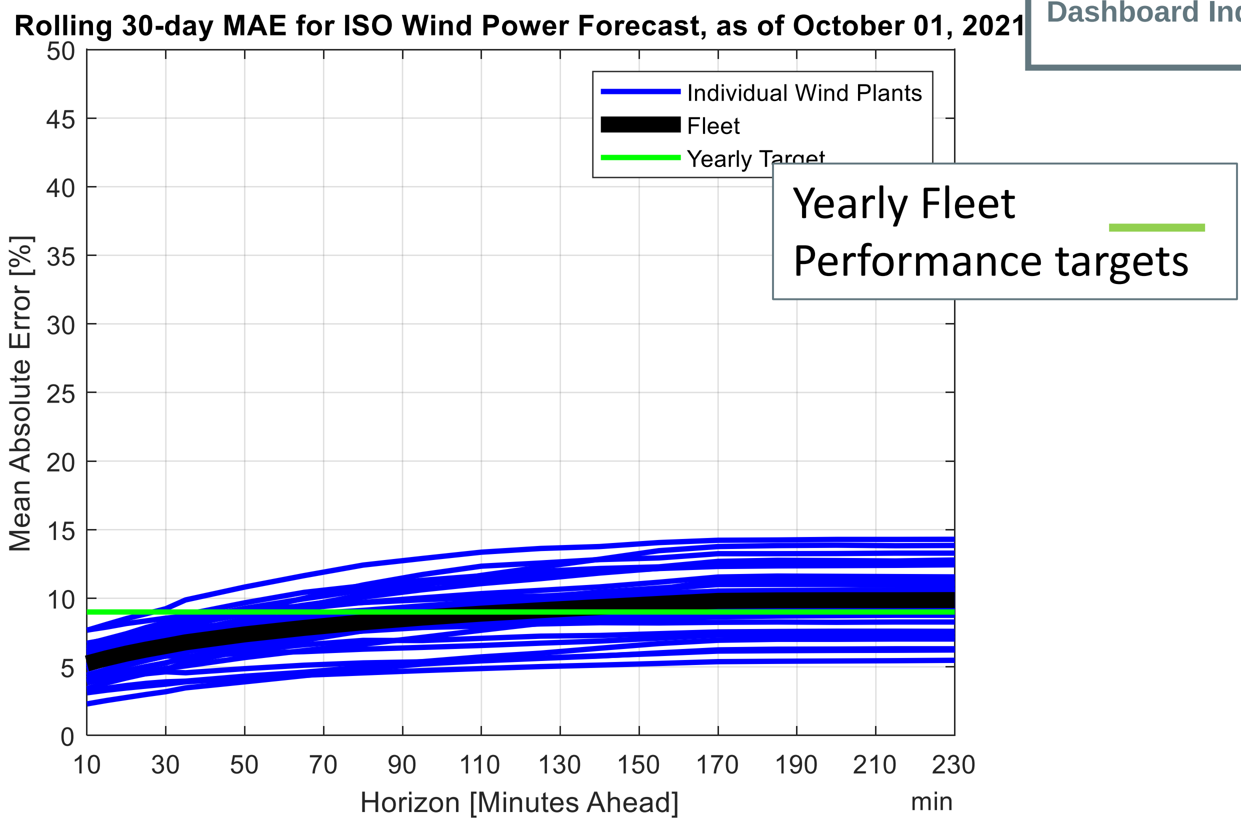


Yearly Fleet Performance targets

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

Wind Power Forecast Error Statistics: Short Term Forecast MAE

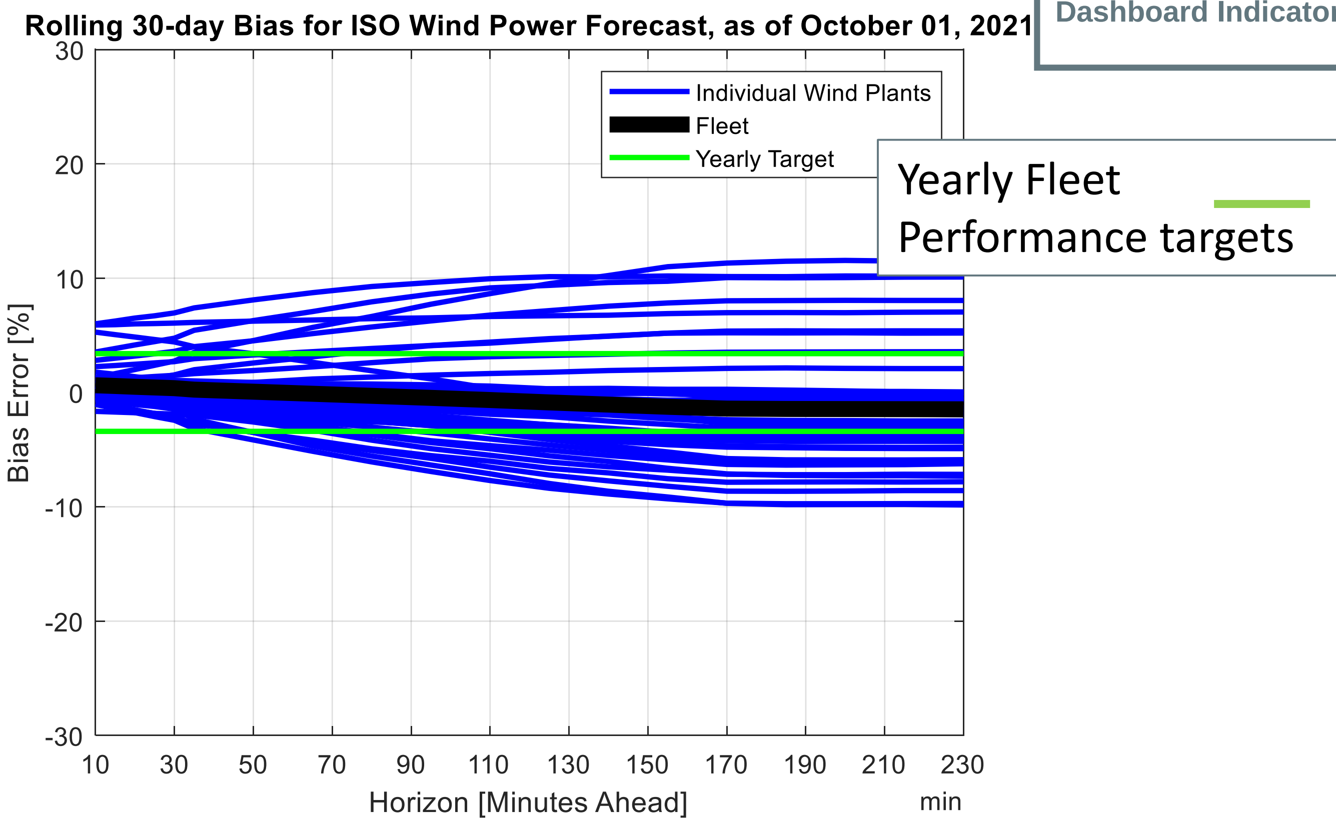
Dashboard Indicator



Ideally, MAE and Bias would be both equal to zero. As is typical, MAE increases with the forecast horizon. MAE and Bias for the fleet of wind power resources are less due to offsetting errors. Across all time frames, the ISO-NE/DNV forecast is very good compared to industry standards, and monthly MAE is within the yearly performance targets up to 130 minutes ahead.

Wind Power Forecast Error Statistics: Short Term Forecast Bias

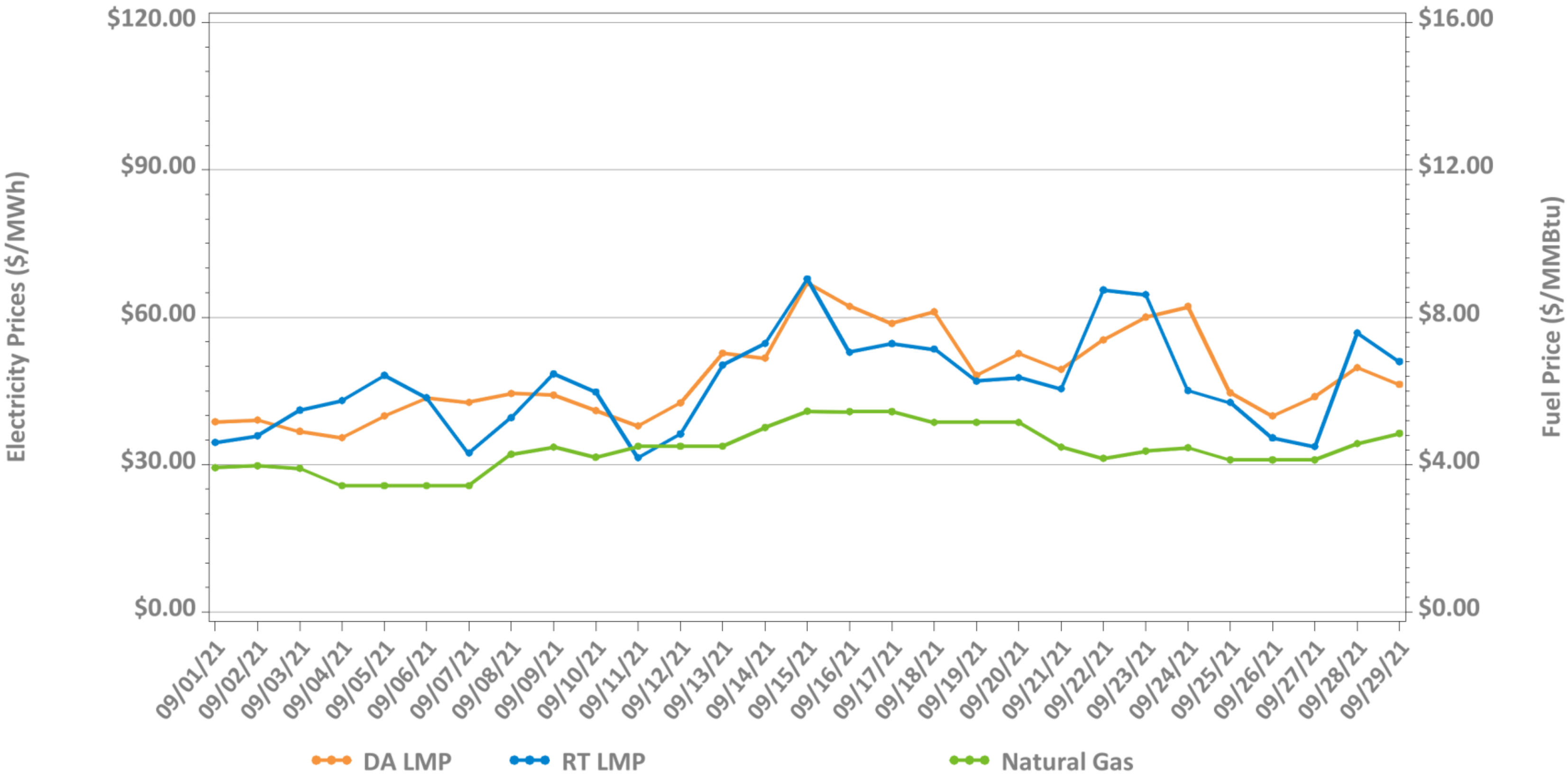
Dashboard Indicator



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 forecast compares well with industry standards, and monthly Bias is within yearly performance.

MARKET OPERATIONS

Daily Average DA and RT ISO-NE Hub Prices and Input Fuel Prices: September 1-29, 2021

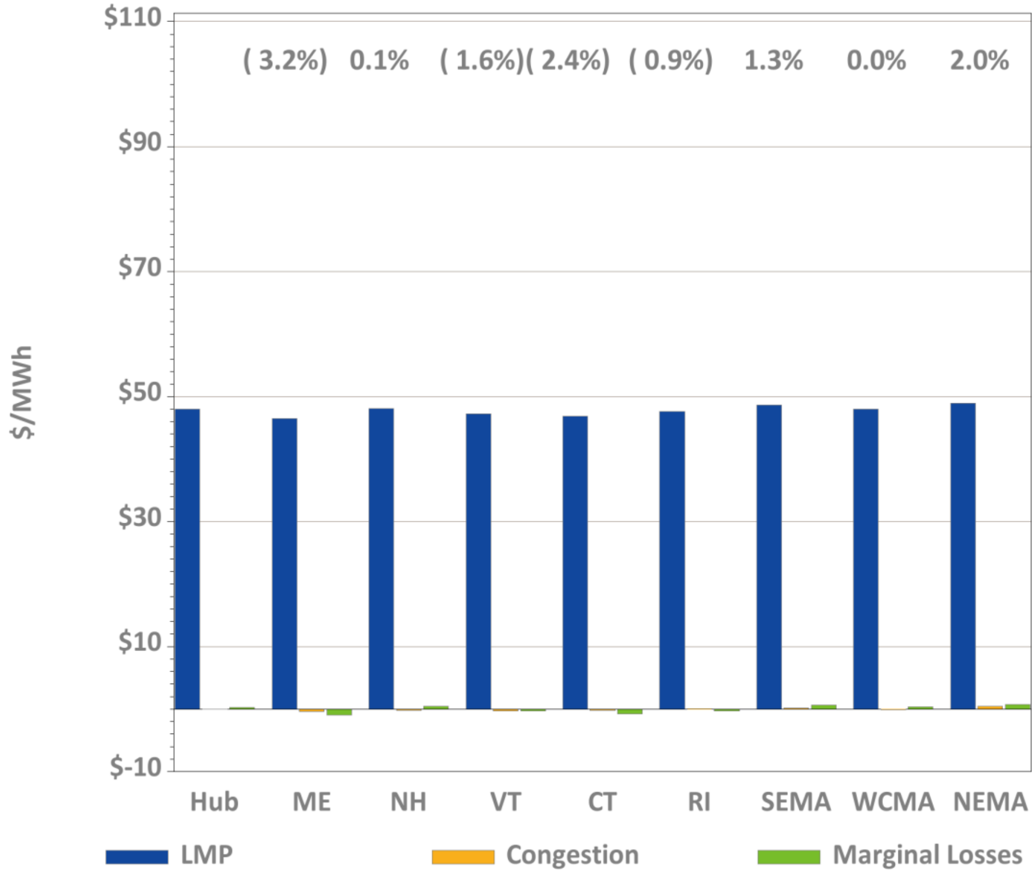


Underlying natural gas data furnished by:

ICE Global markets in clear view

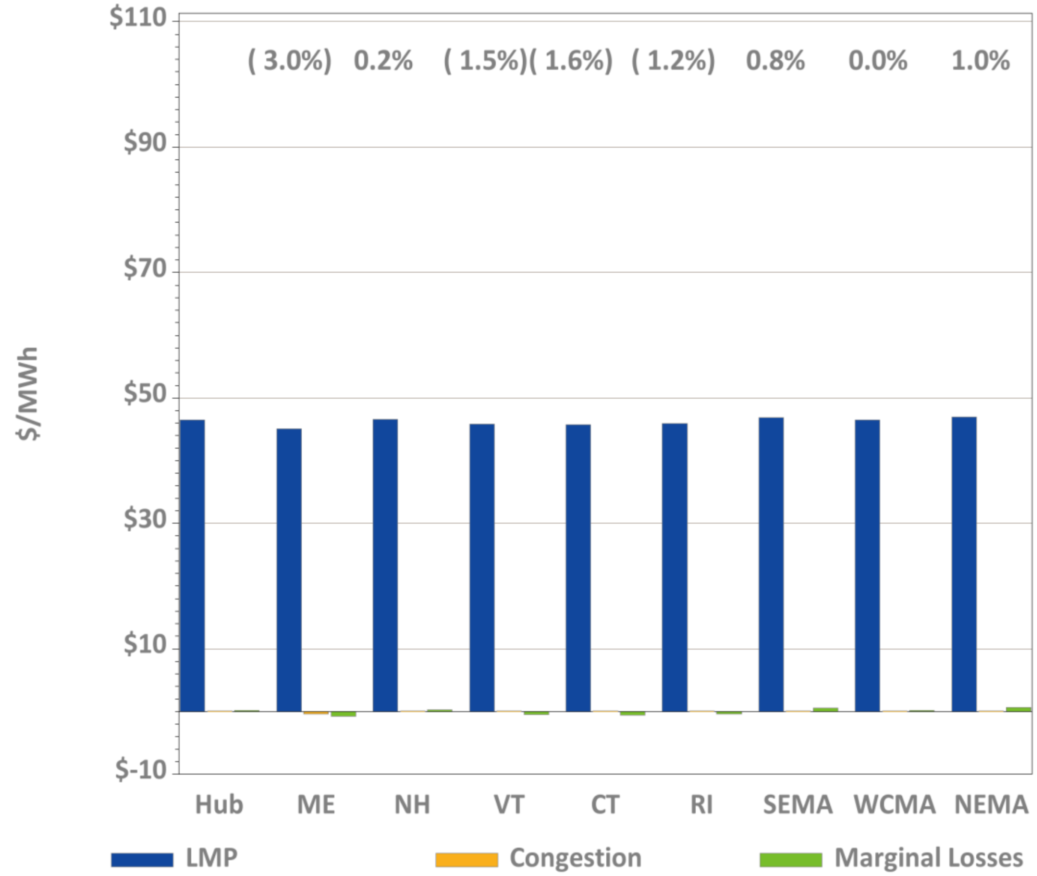
Average price difference over this period (DA-RT): $1.53
Average price difference over this period ABS(DA-RT): $5.55
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 12%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, September 2021



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

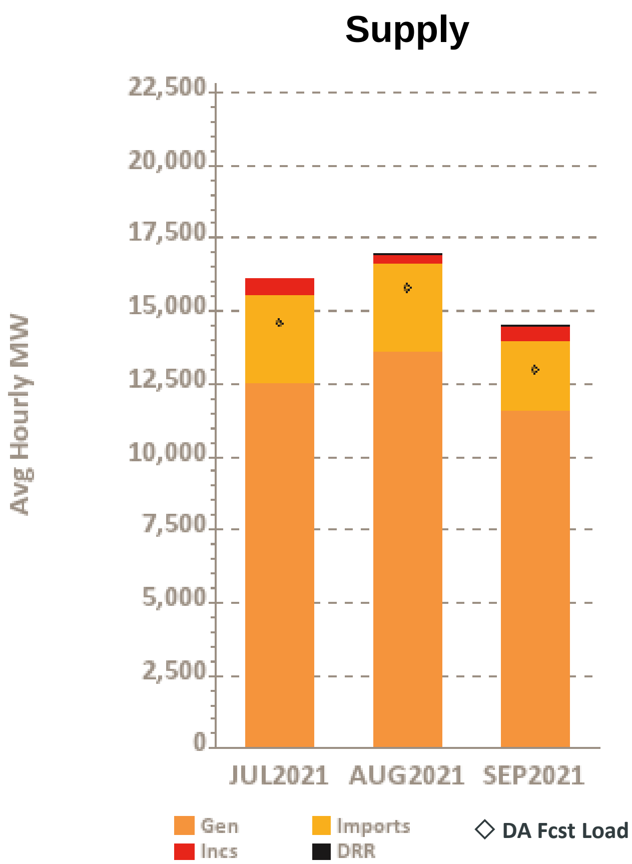
RT LMPs Average by Zone & Hub, September 2021

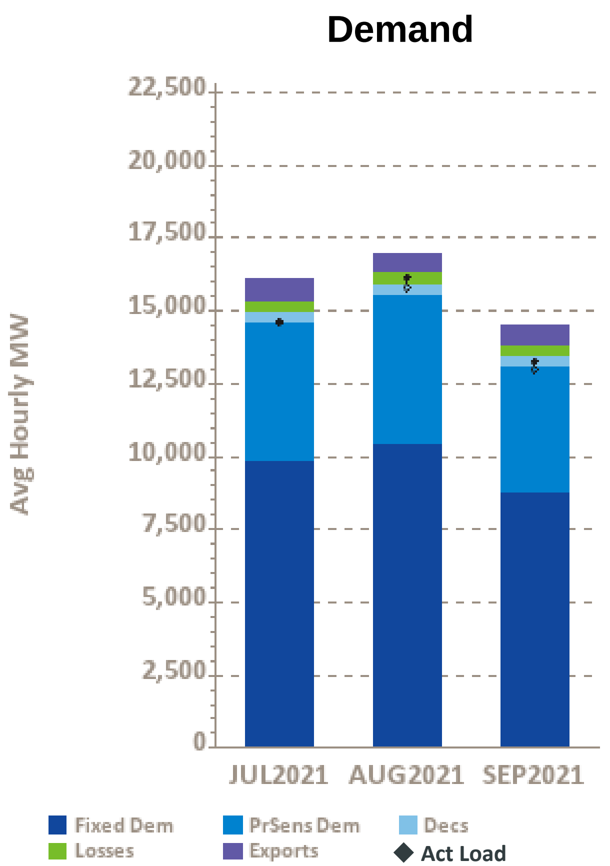


Definitions

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

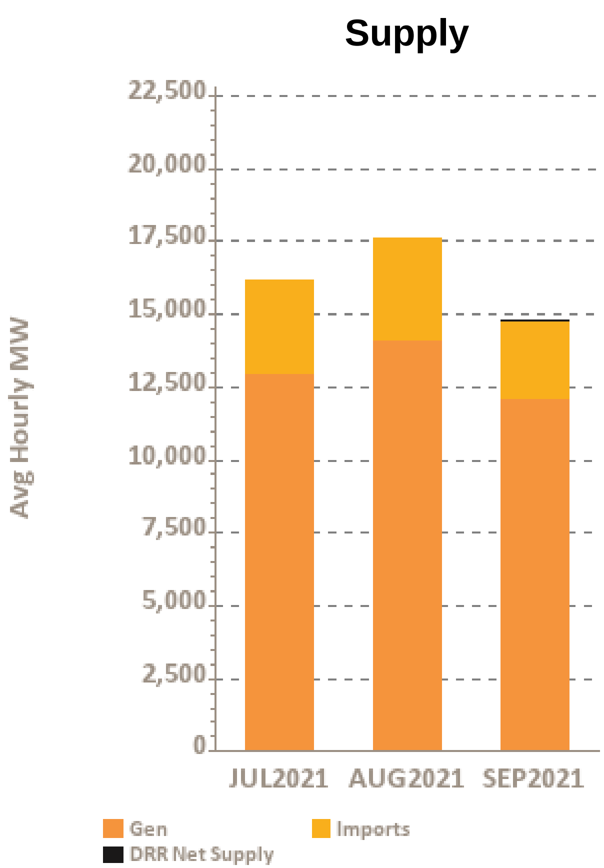


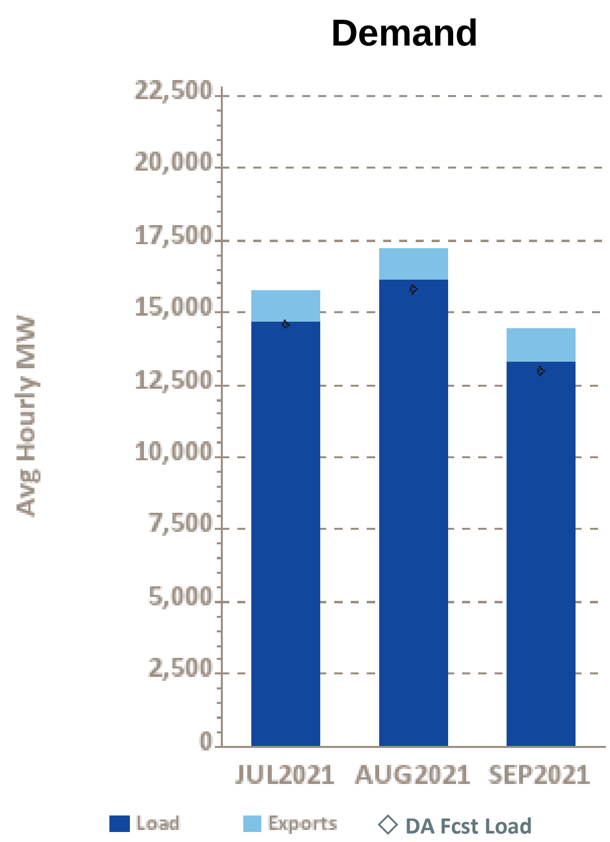


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load
DRR – Demand Response Resource

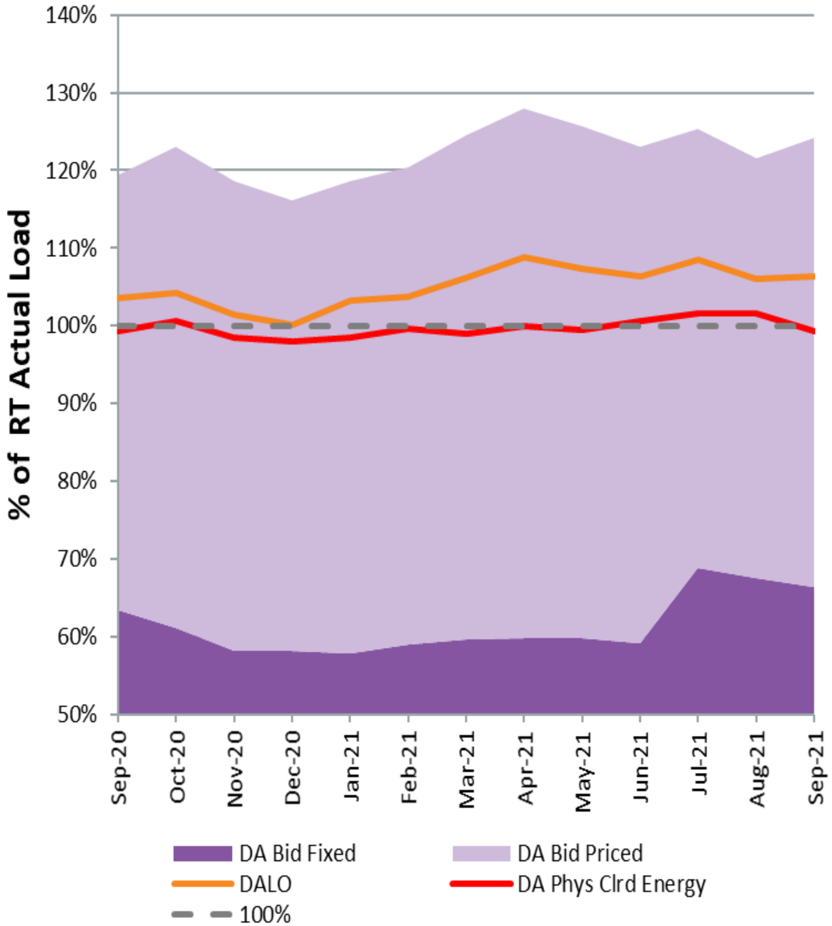
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

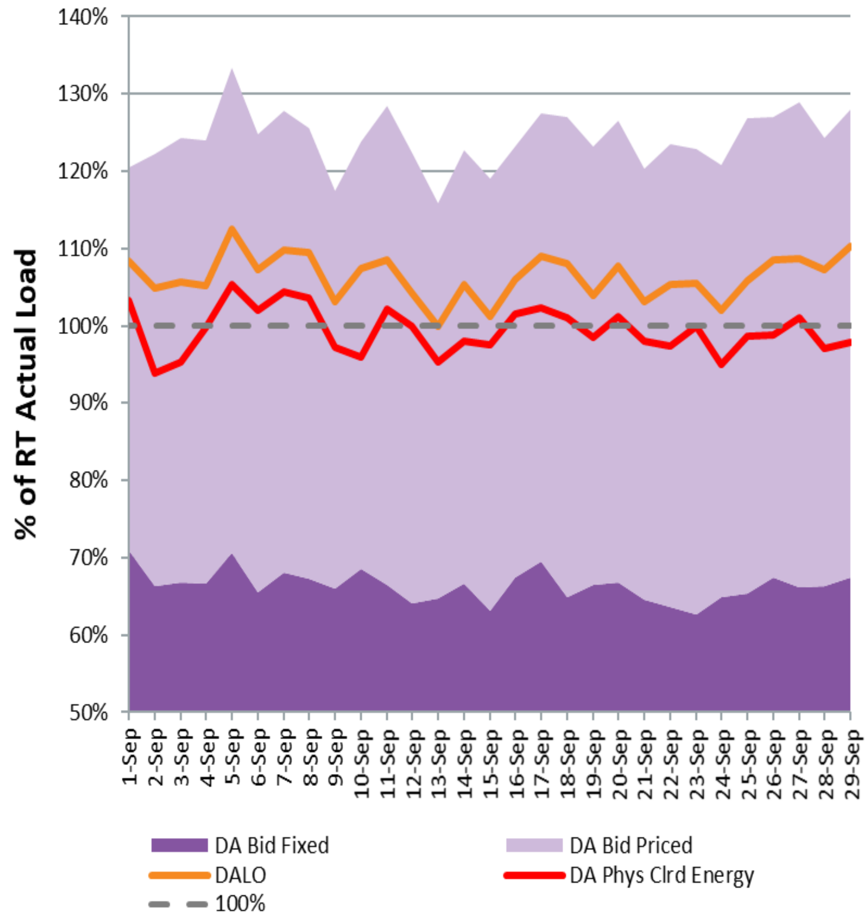
Components of RT Supply and Demand – Last Three Months





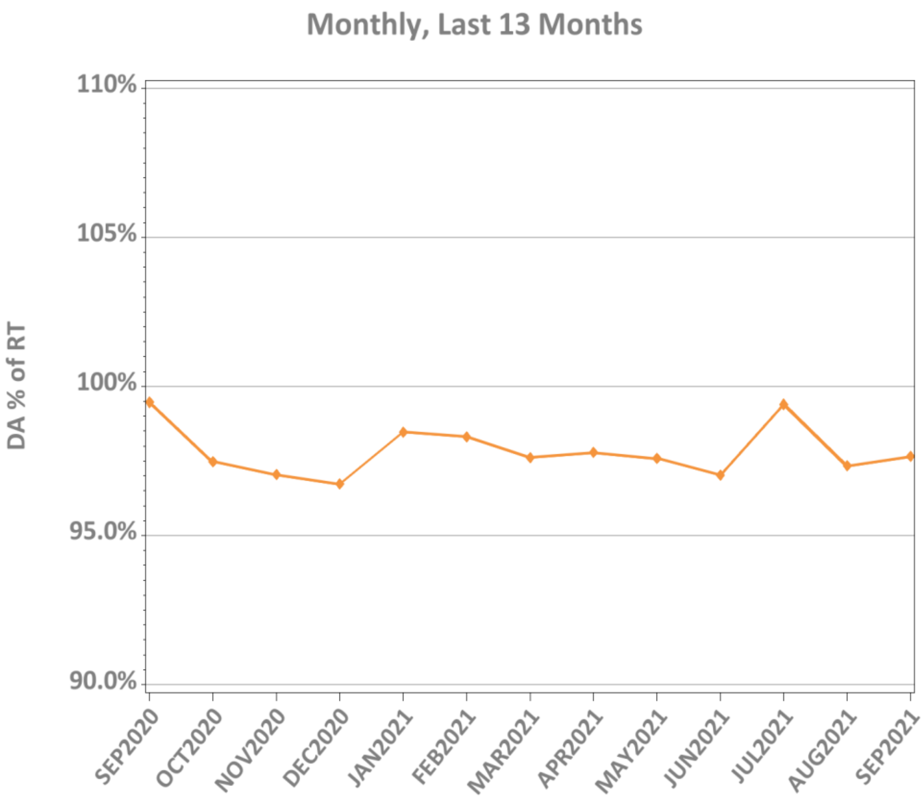
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

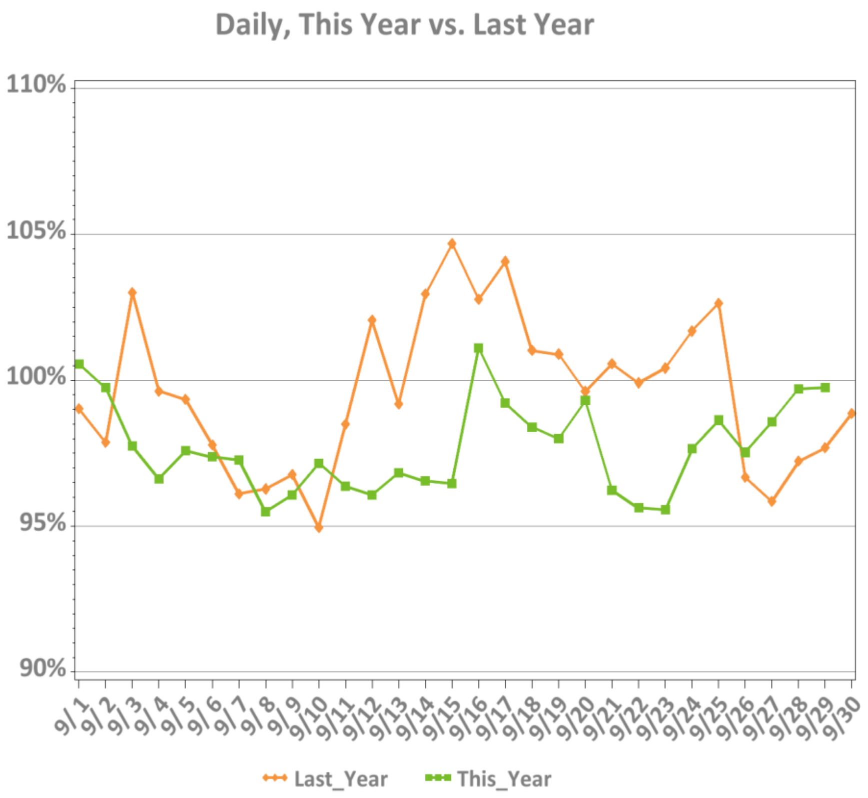




Note: Forecasted peak hour for each day is reflected in the above values. Shown for each day (chart on right) and then averaged for each month (chart on left). 'DA Bid' categories reflect load assets only (Virtual and export bids not reflected.)

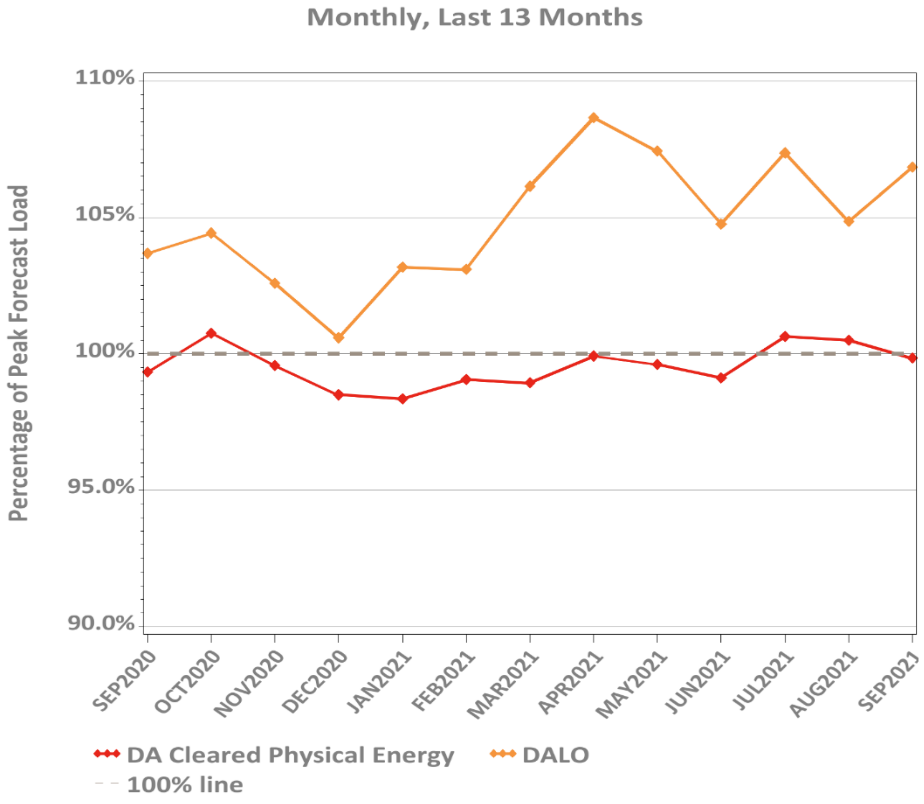
DA vs. RT Load Obligation: September, This Year vs. Last Year

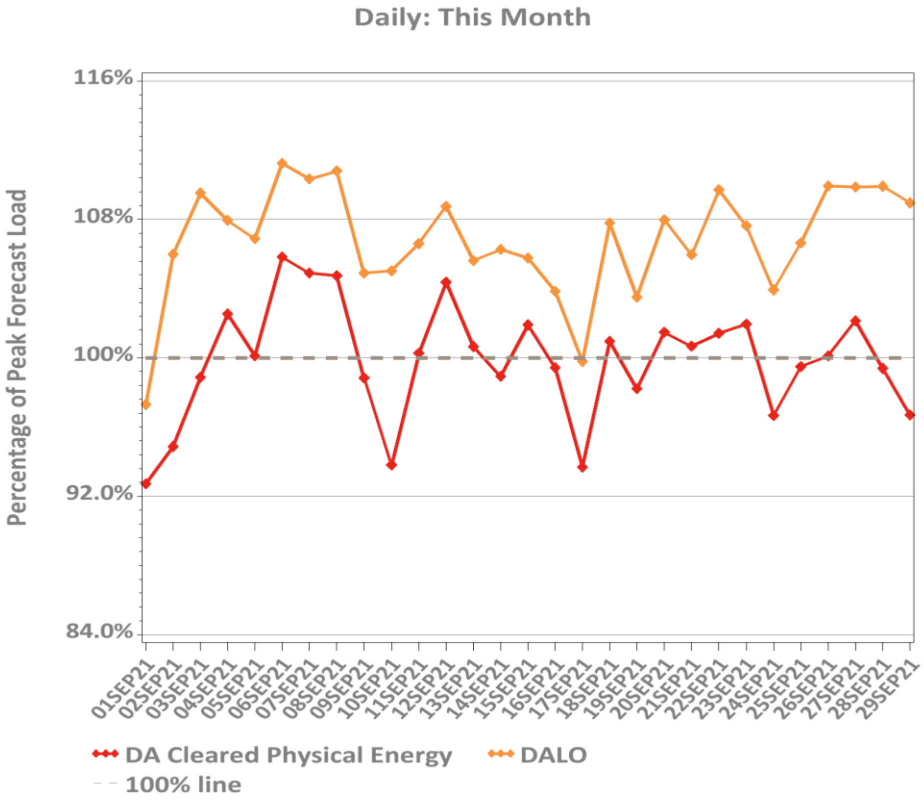




*Hourly average values

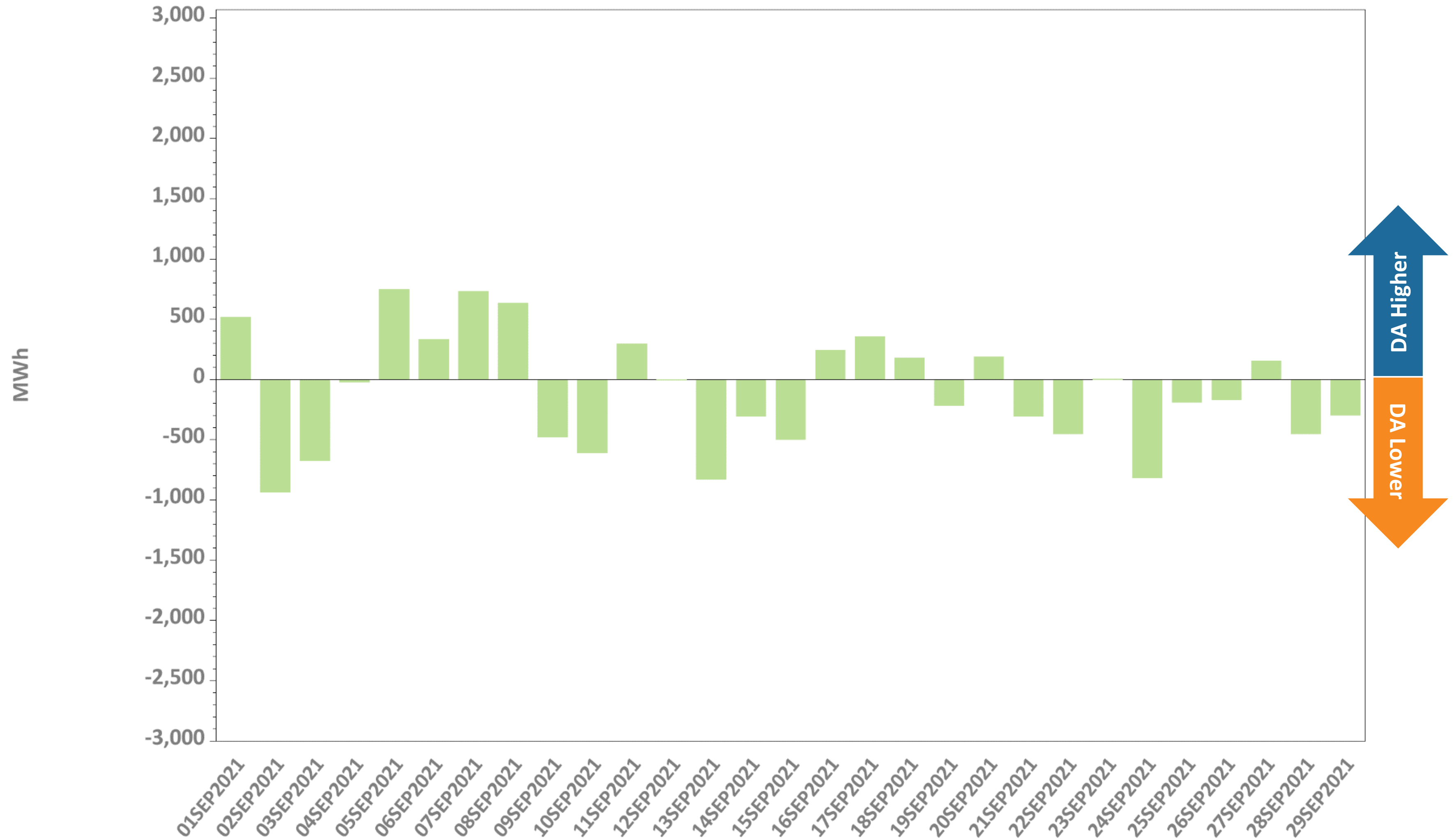
DA Volumes as % of Forecast in Peak Hour





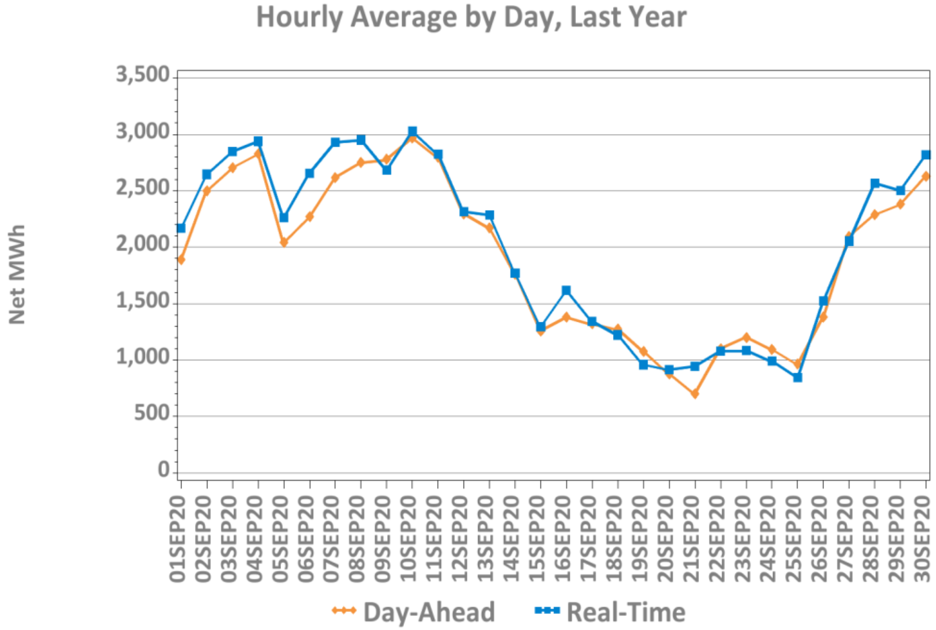
Note: There were no instances of system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) during the month.

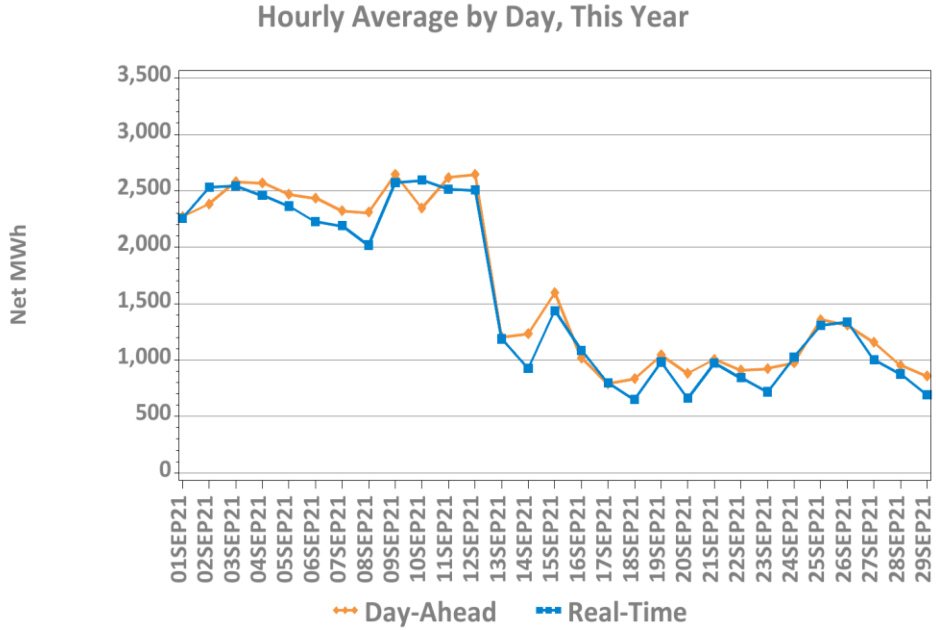
DA Cleared Physical Energy Difference from RT System Load at Forecasted Peak Hour*



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

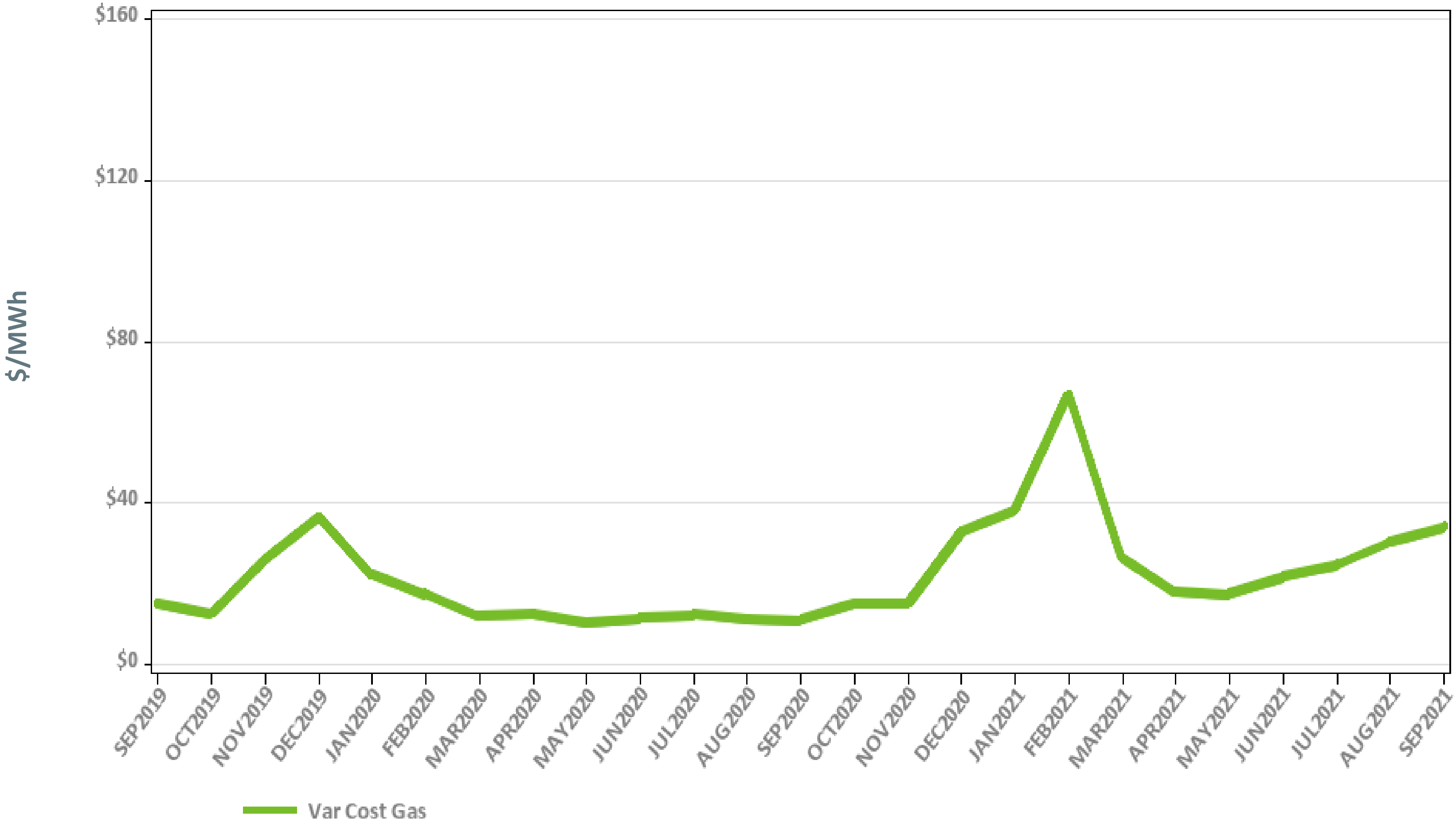
DA vs. RT Net Interchange September 2020 vs. September 2021





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

Variable Production Cost of Natural Gas: Monthly

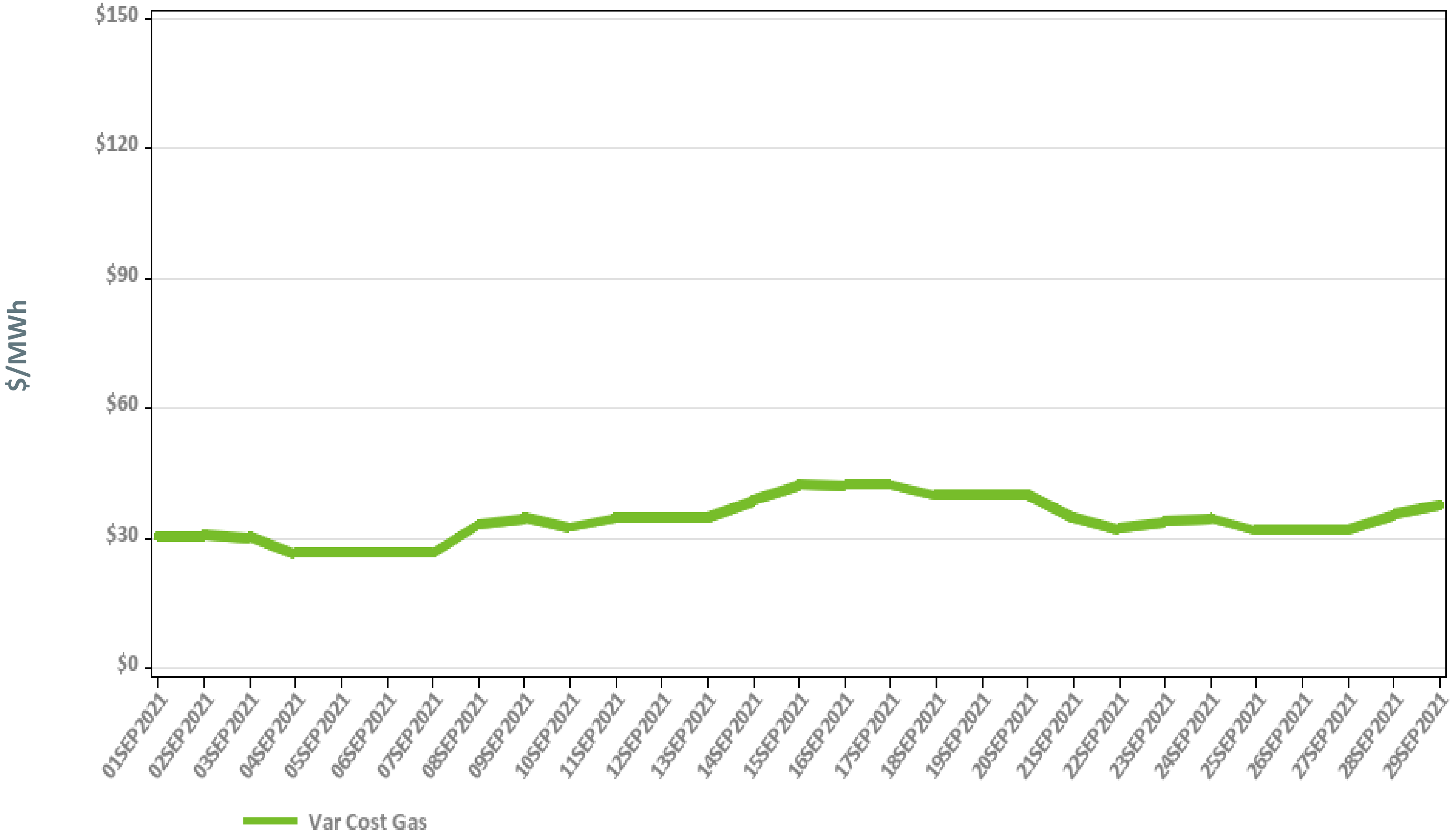


Underlying natural gas data furnished by:

ice Global markets in clear view

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

Variable Production Cost of Natural Gas: Daily

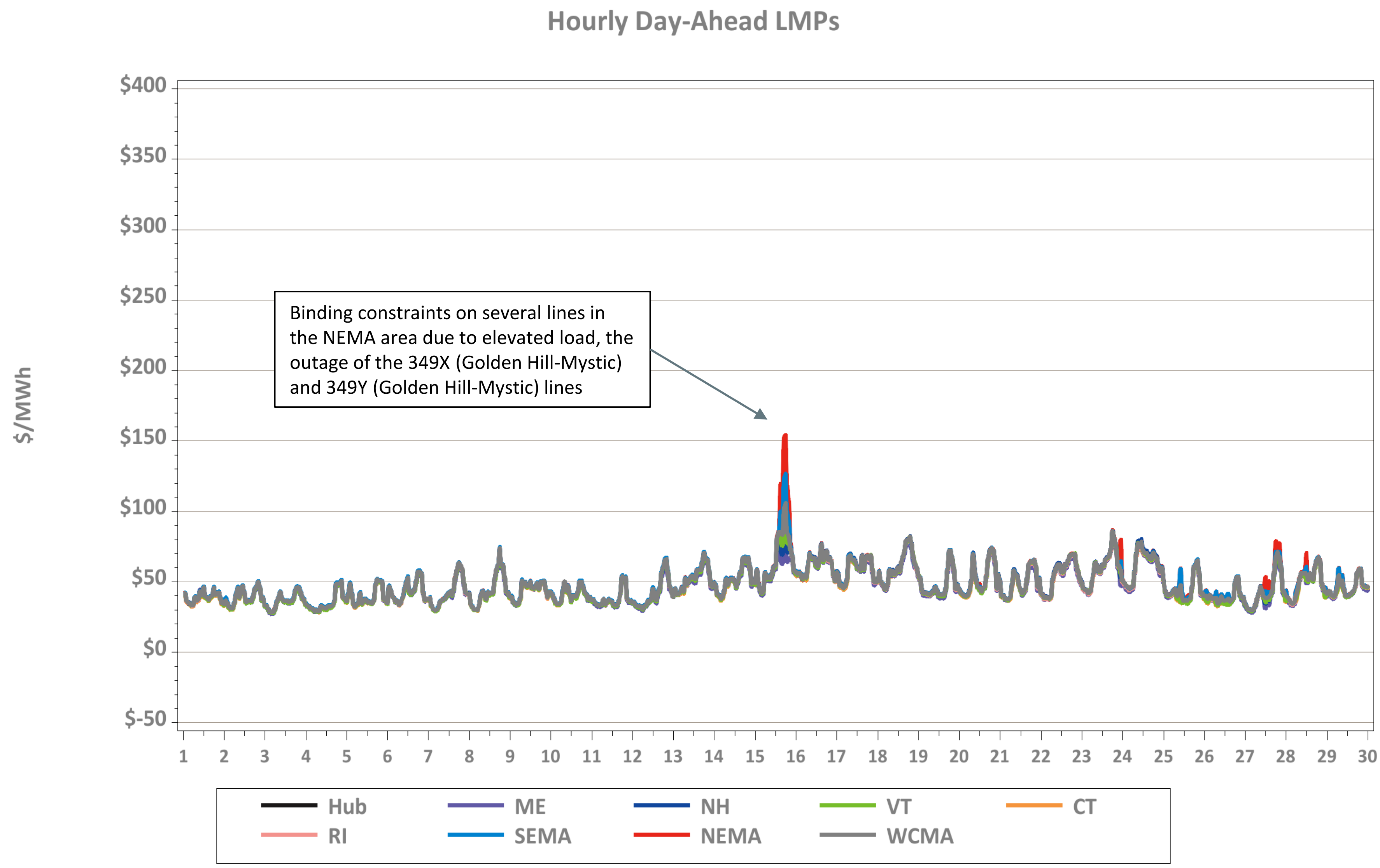


Underlying natural gas data furnished by:

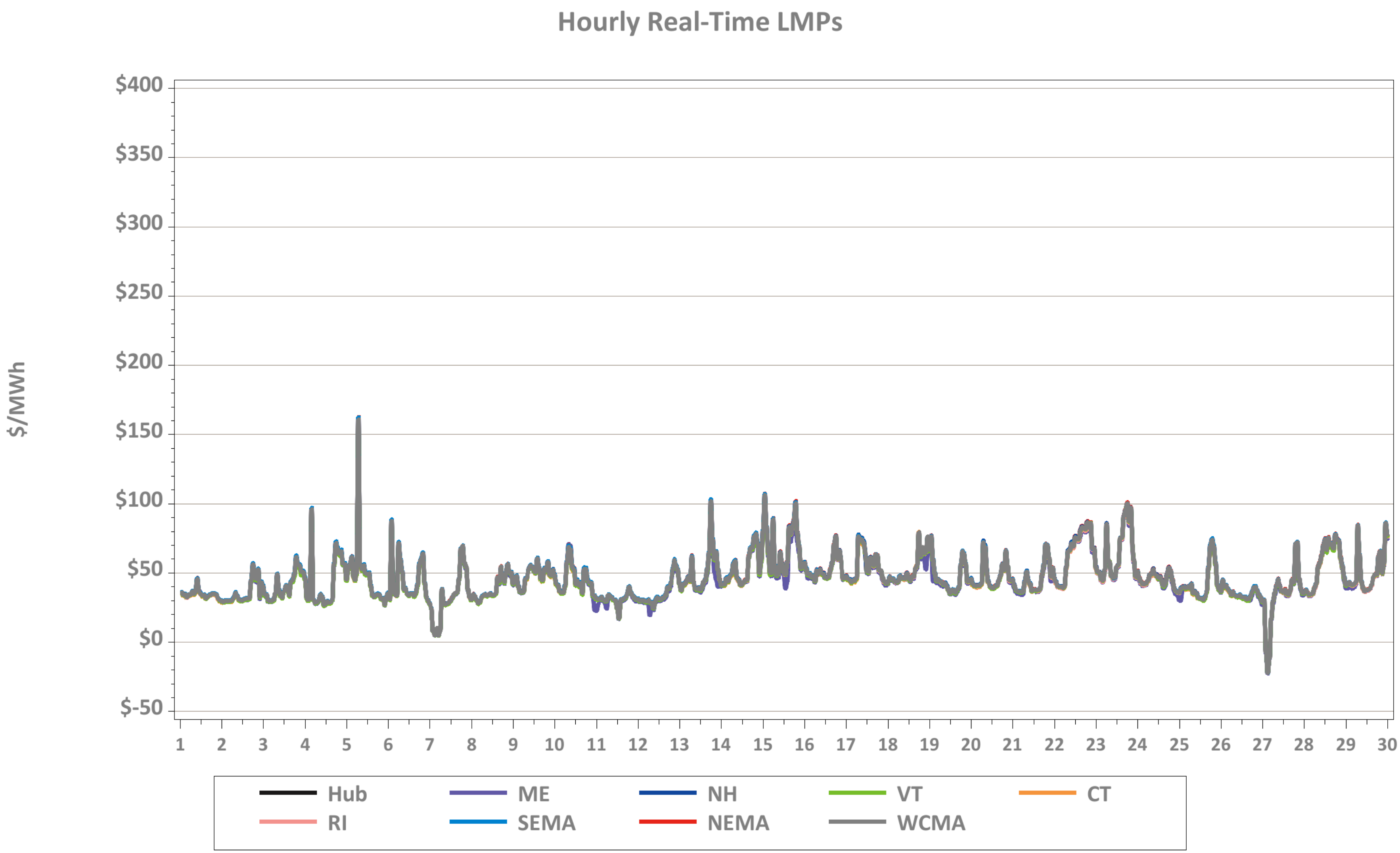
ICE Global markets in clear view

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

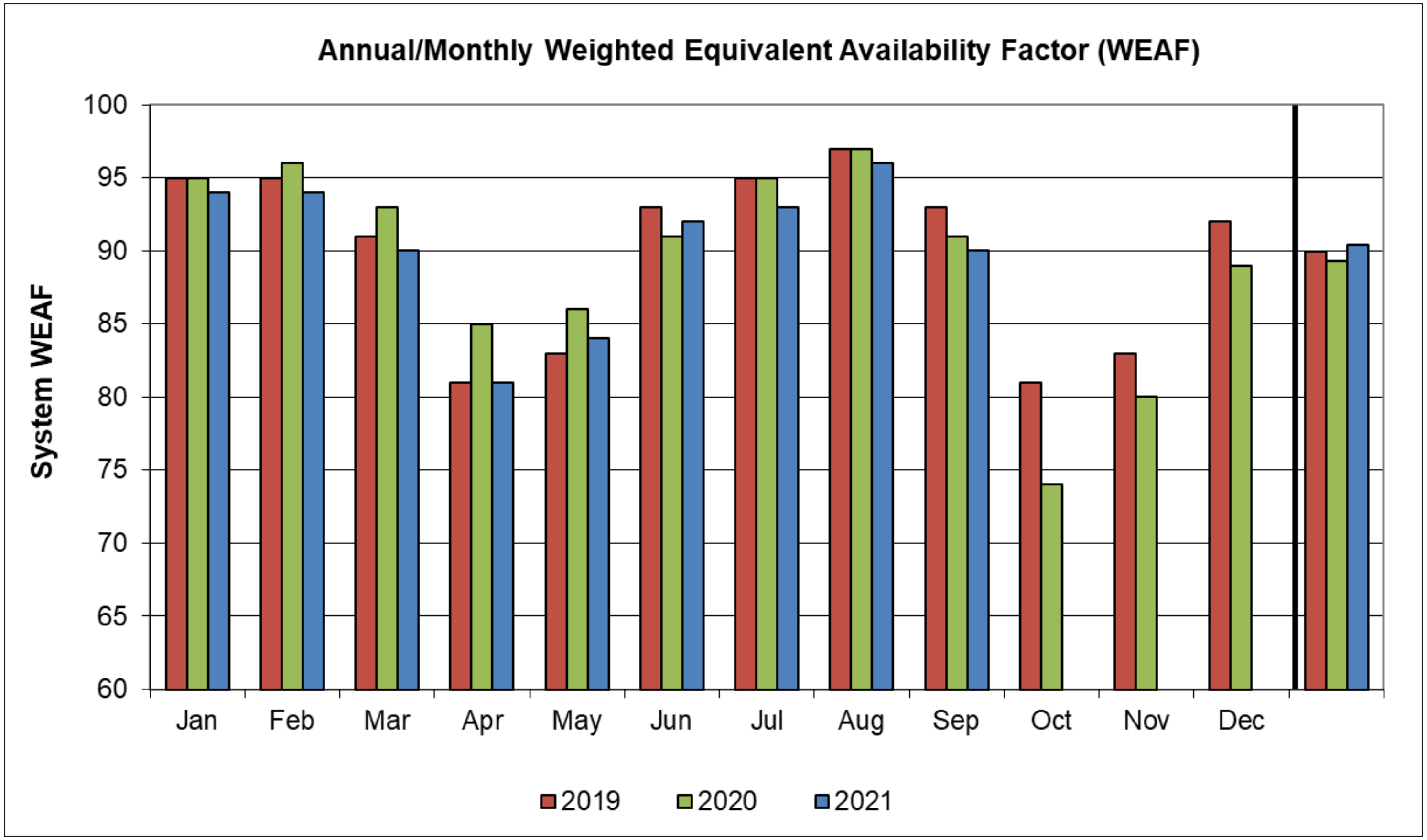
Hourly DA LMPs, September 1-29, 2021



Hourly RT LMPs, September 1-29, 2021



System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2021	94	94	90	81	84	92	93	96	90				90
2020	95	96	93	85	86	91	95	97	91	74	80	89	89
2019	95	95	91	81	83	93	95	97	93	81	83	92	90

Data as of 9/28/2021

BACK-UP DETAIL

DEMAND RESPONSE

Capacity Supply Obligation (CSO) MW by Demand Resource Type for October 2021

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	85.4	202.5	0.0	287.9
NH	40.3	147.6	0.0	187.9
VT	38.1	125.6	0.0	163.7
CT	139.3	120.1	614.8	874.3
RI	39.2	323.4	0.0	362.6
SEMA	44.3	506.9	0.0	551.2
WCMA	84.1	539.3	39.6	663.0
NEMA	60.7	860.7	0.0	921.4
Total	**531.4**	**2,826.0**	**654.4**	**4,011.8**

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

NEW GENERATION

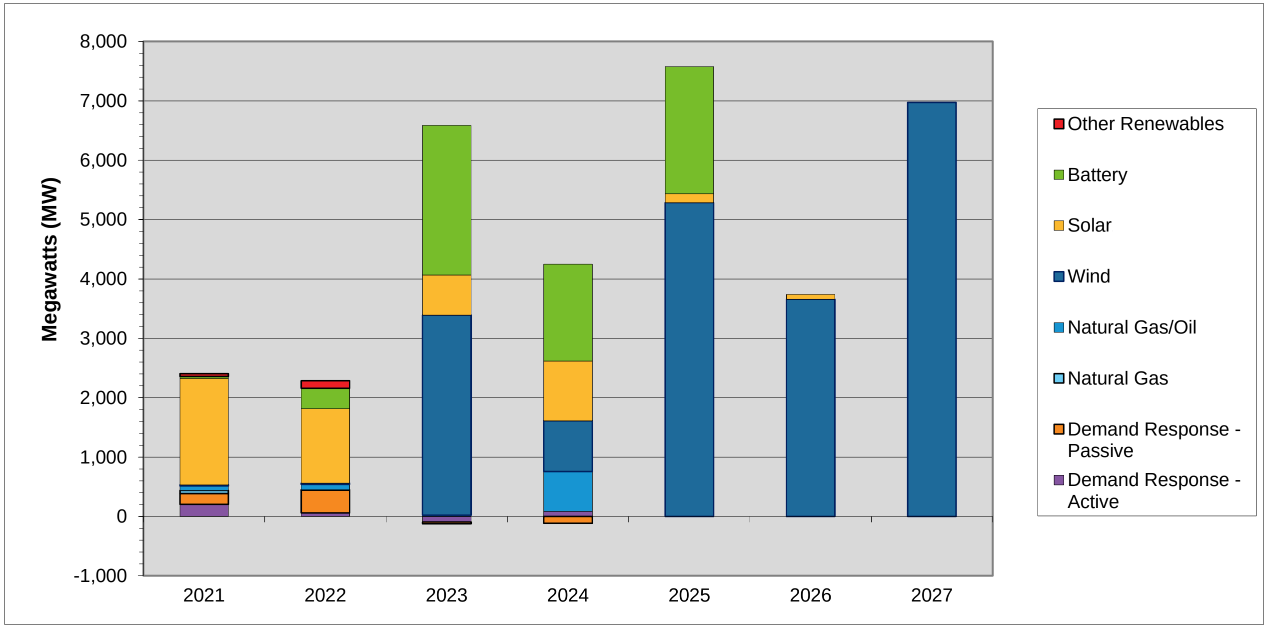
New Generation Update

Based on Queue as of 10/01/21

- Four new projects totaling 325 MW applied for interconnection study since the last update
  - They consist of one battery and three solar with battery projects with in-service dates ranging from 2022 to 2023
- One project went commercial and five projects were withdrawn
- In total, 294 generation projects are currently being tracked by the ISO, totaling approximately 32,907 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



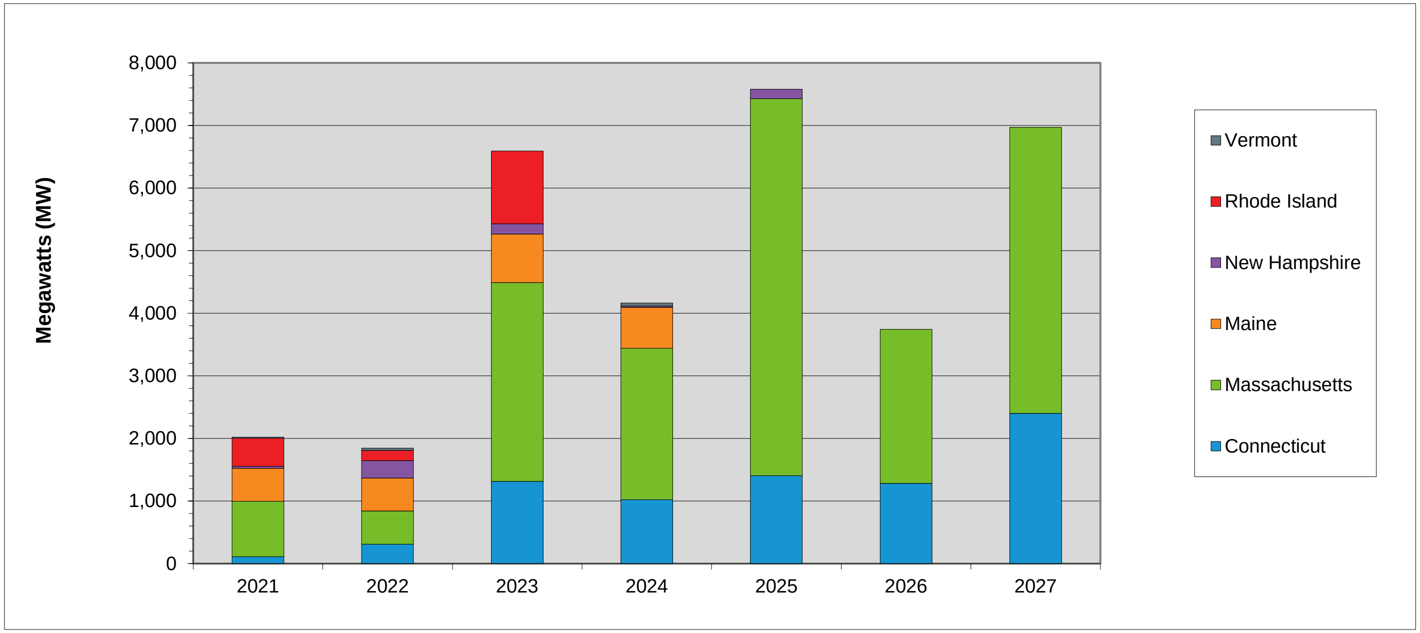
	2021	2022	2023	2024	2025	2026	2027	Total MW	% of Total[1]
Other Renewables	48	128	0	0	0	0	0	176	0.5
Battery	34	347	2,524	1,630	2,140	0	0	6,675	19.9
Solar[2]	1,792	1,251	675	1,010	150	83	0	4,961	14.8
Wind	19	20	3,367	852	5,287	3,658	6,972	20,175	60.1
Natural Gas/Oil[3]	76	89	23	672	0	0	0	860	2.6
Natural Gas	49	11	0	0	0	0	0	60	0.2
Demand Response - Passive	184	380	-28	-114	0	0	0	422	1.3
Demand Response - Active	204	62	-94	86	0	0	0	258	0.8
Totals	**2,406**	**2,288**	**6,467**	**4,136**	**7,577**	**3,741**	**6,972**	**33,587**	**100.0**

[1] Sum may not equal 100% due to rounding
[2] This category includes both solar-only, and co-located solar and battery projects
[3] The projects in this category are dual fuel, with either gas or oil as the primary fuel

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

Actual and Projected Annual Generator Capacity Additions

By State



	2021	2022	2023	2024	2025	2026	2027	Total MW	% of Total[1]
Vermont	15	40	0	50	0	0	0	105	0.3
Rhode Island	450	160	1,161	0	0	0	0	1,771	5.4
New Hampshire	30	281	164	20	150	0	0	645	2.0
Maine	526	523	774	652	0	0	0	2,475	7.5
Massachusetts	888	532	3,178	2,421	6,022	2,458	4,572	20,071	61.0
Connecticut	109	310	1,312	1,021	1,405	1,283	2,400	7,840	23.8
Totals	**2,018**	**1,846**	**6,589**	**4,164**	**7,577**	**3,741**	**6,972**	**32,907**	**100.0**

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

New Generation Projection

By Fuel Type

Unit Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	0	0	0	0	0	0
Battery Storage	37	6,675	0	0	37	6,675
Fuel Cell	3	40	1	10	2	30
Hydro	3	99	2	71	1	28
Natural Gas	6	60	0	0	6	60
Natural Gas/Oil	7	860	1	14	6	846
Nuclear	1	37	0	0	1	37
Solar	207	4,961	19	316	188	4,645
Wind	30	20,175	1	15	29	20,160
Total	294	32,907	24	426	270	32,481

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

New Generation Projection

By Operating Type

Operating Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	6	110	2	15	4	95
Intermediate	8	818	1	14	7	804
Peaker	250	11,804	20	382	230	11,422
Wind Turbine	30	20,175	1	15	29	20,160
Total	294	32,907	24	426	270	32,481

- 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	
Unit 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	0	0	0	0	0	0	0	0	0	0
Battery Storage	37	6,675	0	0	0	0	37	6,675	0	0
Fuel Cell	3	40	3	40	0	0	0	0	0	0
Hydro	3	99	2	33	0	0	1	66	0	0
Natural Gas	6	60	0	0	3	43	3	17	0	0
Natural Gas/Oil	7	860	0	0	5	775	2	85	0	0
Nuclear	1	37	1	37	0	0	0	0	0	0
Solar	207	4,961	0	0	0	0	207	4,961	0	0
Wind	30	20,175	0	0	0	0	0	0	30	20,175
Total	294	32,907	6	110	8	818	250	11,804	30	20,175

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

FORWARD CAPACITY MARKET

Capacity Supply Obligation (CSO) 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	603.776	-55.361	587.270	-16.506
	Passive Demand	2,975.36	3,045.073	69.713	3,123.232	78.159	3,322.722	199.490
Demand Total		**3,599.81**	**3,704.21**	**104.4**	**3,727.008**	**22.798**	**3,909.992**	**182.984**
Generator	*Non-Intermittent*	29,130.75	29,244.404	113.654	28,620.245	-624.159	28,941.276	321.031
	Intermittent	880.317	806.609	-73.708	660.932	-145.677	663.179	2.247
Generator Total		**30,011.07**	**30,051.013**	**39.943**	**29,281.177**	**-769.836**	**29,604.455**	**323.278**
Import Total		**1,217**	**1,305.487**	**88.487**	**1,307.587**	**2.10**	**1207.78**	**-99.807**
Grand Total*		**34,827.88**	**35,060.710**	**232.83**	**34,315.772**	**-744.94**	**34,722.227**	**406.455**
Net ICR (NICR)		**33,725**	**33,550**	**-175**	**32,230**	**-1,320**	**32,925**	**695**

* 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.

ARA – Annual Reconfiguration Auction
FCA – Forward Capacity Auction
ICR – Installed Capacity Requirement

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	683.116	-2.438	658.659	-24.457		
	Passive Demand	3,354.69	3,407.507	52.817	3,450.899	43.392		
Demand Total		**4,040.244**	**4,090.623**	**50.38**	**4,109.558**	**18.935**		
Generator	*Non-Intermittent*	28,586.498	27,868.341	-718.157	28,105.411	237.07		
	Intermittent	1,024.792	901.672	-123.12	896.285	-5.387		
Generator Total		**2,9611.29**	**28,770.013**	**-841.28**	**29,001.696**	**231.683**		
Import Total		**1,187.69**	**1,292.41**	**104.72**	**1,292.41**	**0**		
Grand Total*		**34,839.224**	**34,153.046**	**-686.18**	**34,403.664**	**250.618**		
Net ICR (NICR)		**33,750**	**32,465**	**-1,285**	**32,765**	**300**		

* 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 14

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*	592.043	688.07	96.027				
Demand	*Passive Demand*	3,327.071	3,327.932	0.861				
Demand Total		**3,919.114**	**4,016.002**	**96.888**				
Generator	*Non-Intermittent*	27,816.902	28,275.143	458.241				
Generator	*Intermittent*	1,160.916	1,128.446	-32.47				
Generator Total		**28,977.818**	**29,403.589**	**425.771**				
Import Total		**1,058.72**	**1,058.72**	**0**				
Grand Total*		**33,955.652**	**34,478.311**	**522.661**				
Net ICR (NICR)		**32,490**	**32,980**	**490**				

* 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 15

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*	677.673						
Demand	*Passive Demand*	3,212.865						
Demand Total		**3,890.538**						
Generator	*Non-Intermittent*	28,154.203						
Generator	*Intermittent*	1,089.265						
Generator Total		**29,243.468**						
Import Total		**1,487.059**						
Grand Total*		**34,621.065**						
Net ICR (NICR)		**33,270**						

* 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
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**
2023-24	Active	560.55	31.493	592.043
	Passive	3,035.51	291.565	3,327.07
	Grand Total	**3596.056**	**323.058**	**3919.114**
2024-25	Active	674.153	3.520	677.673
	Passive	3,046.064	166.801	3,212.865
	Grand Total	**3,720.217**	**170.321**	**3,890.538**

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

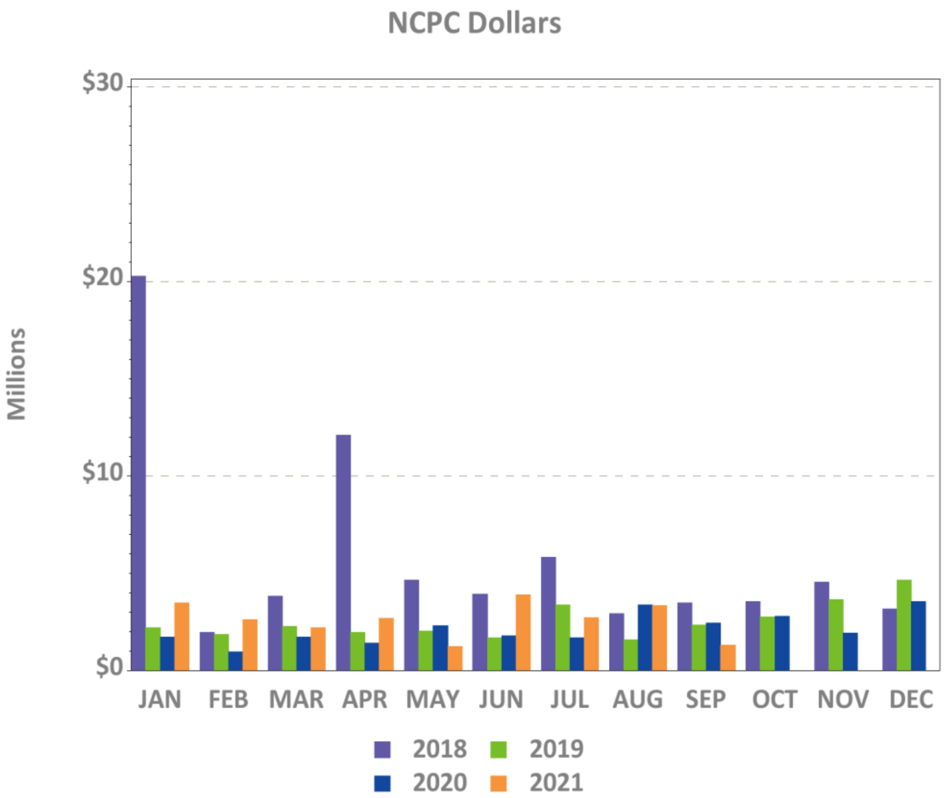
Definitions

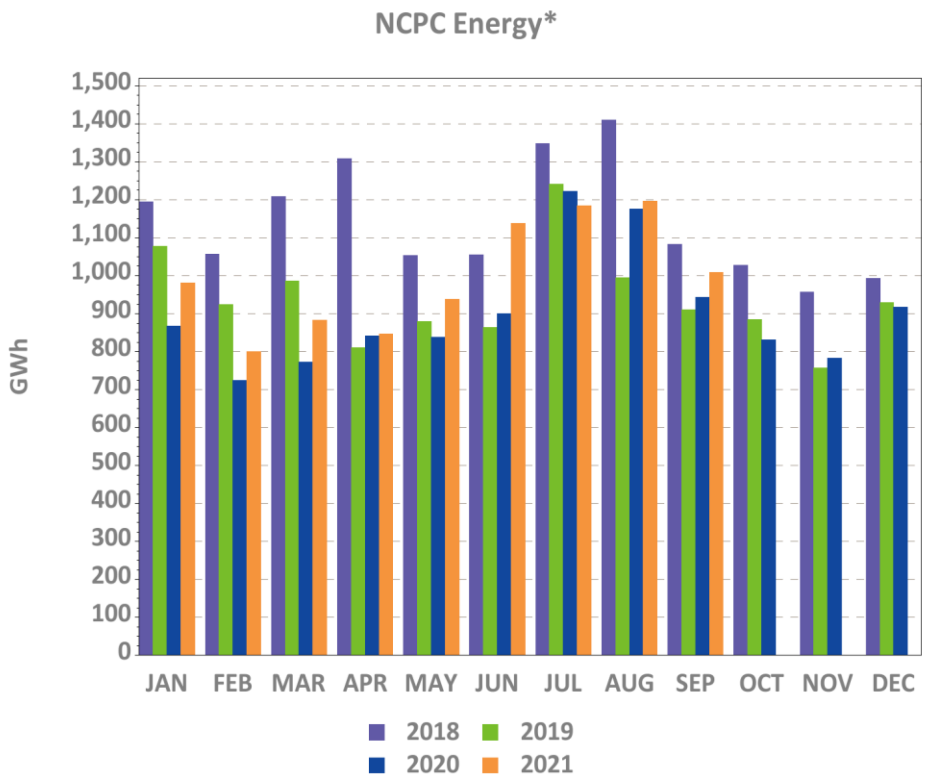
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing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

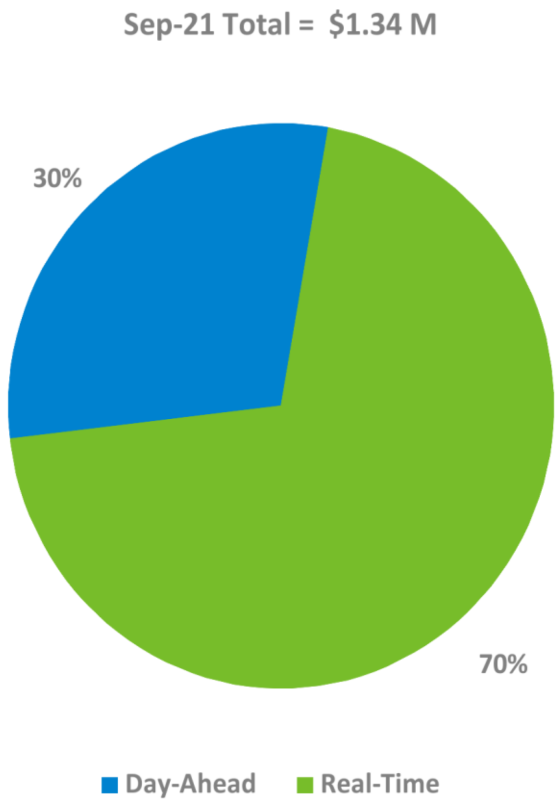
Year-Over-Year Total NCPC Dollars and Energy

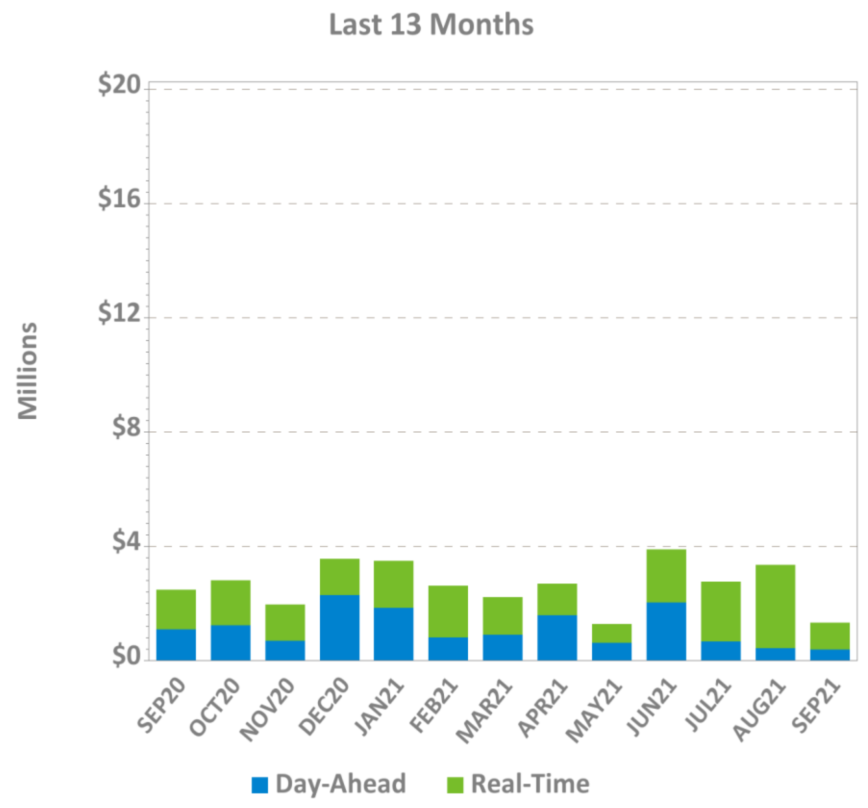




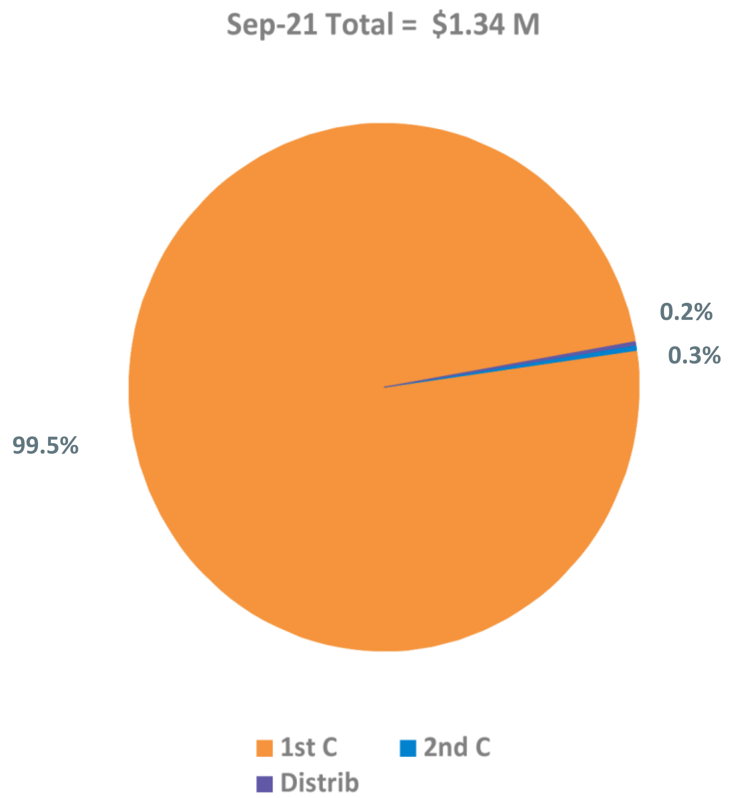
* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

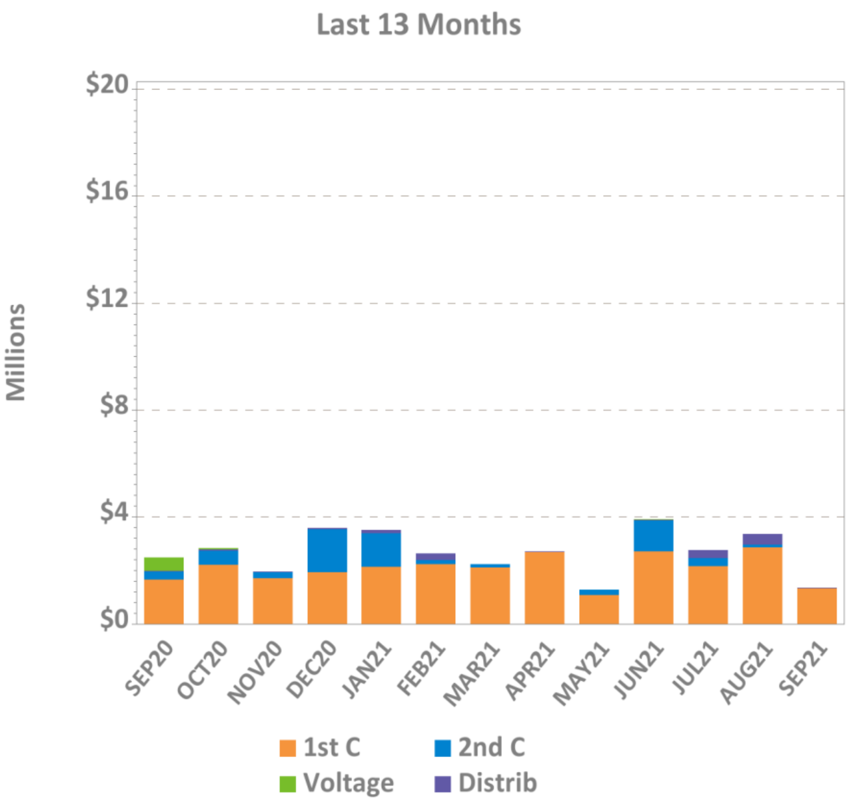
DA and RT NCPC Charges





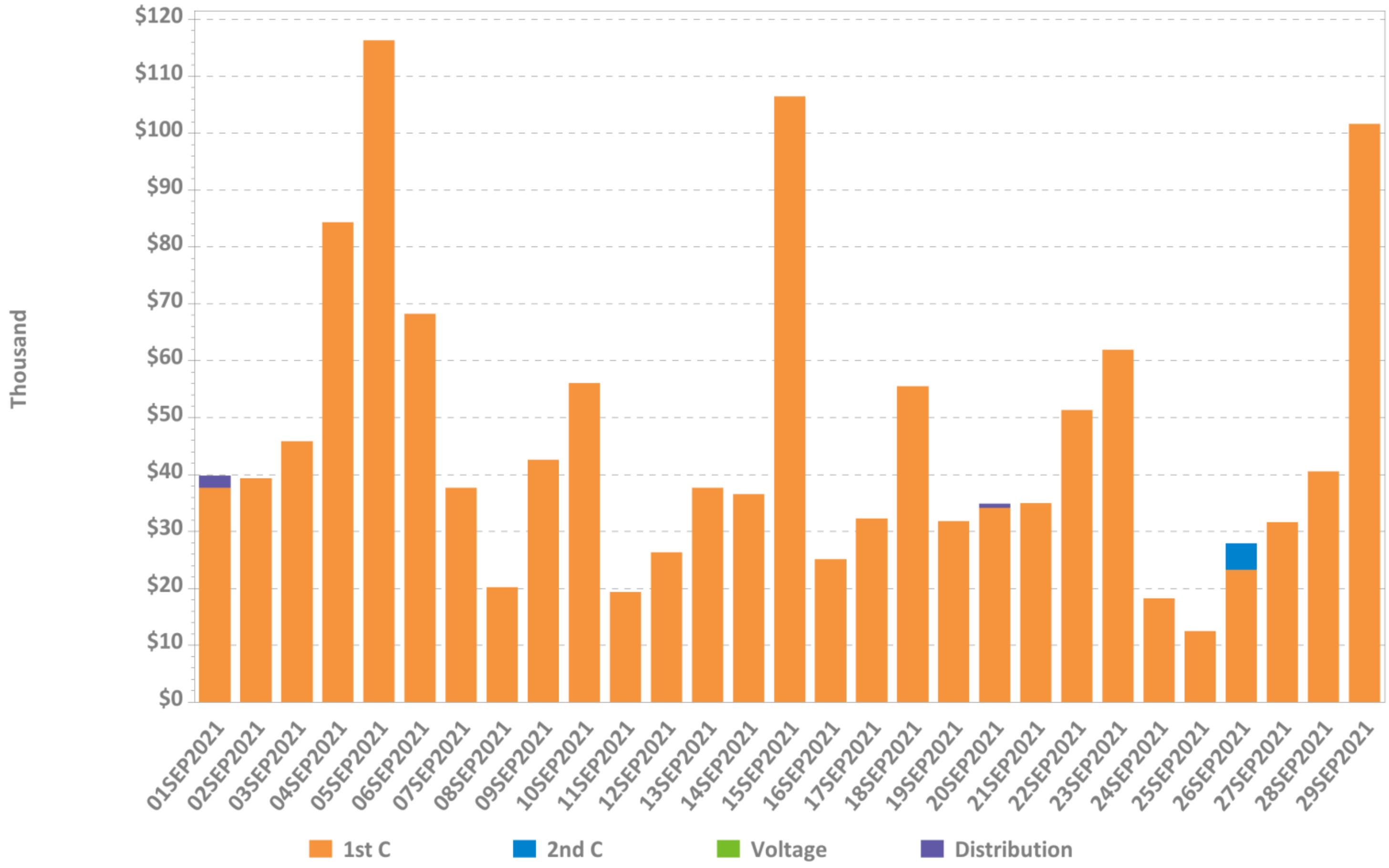
NCPC Charges by Type



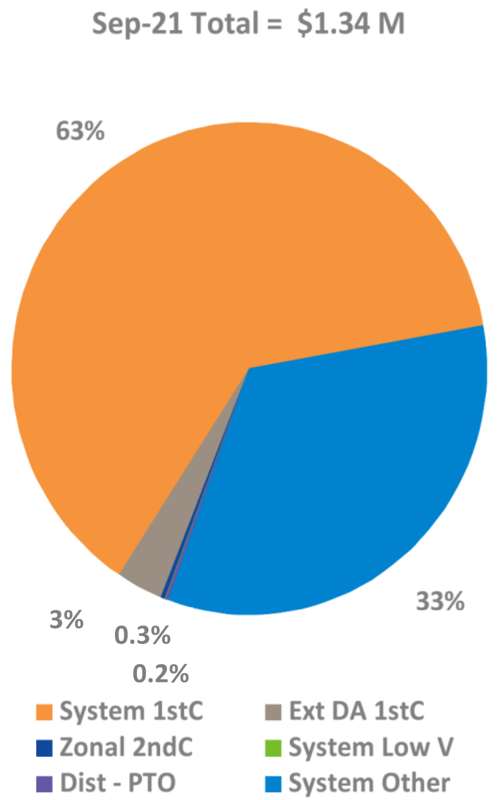


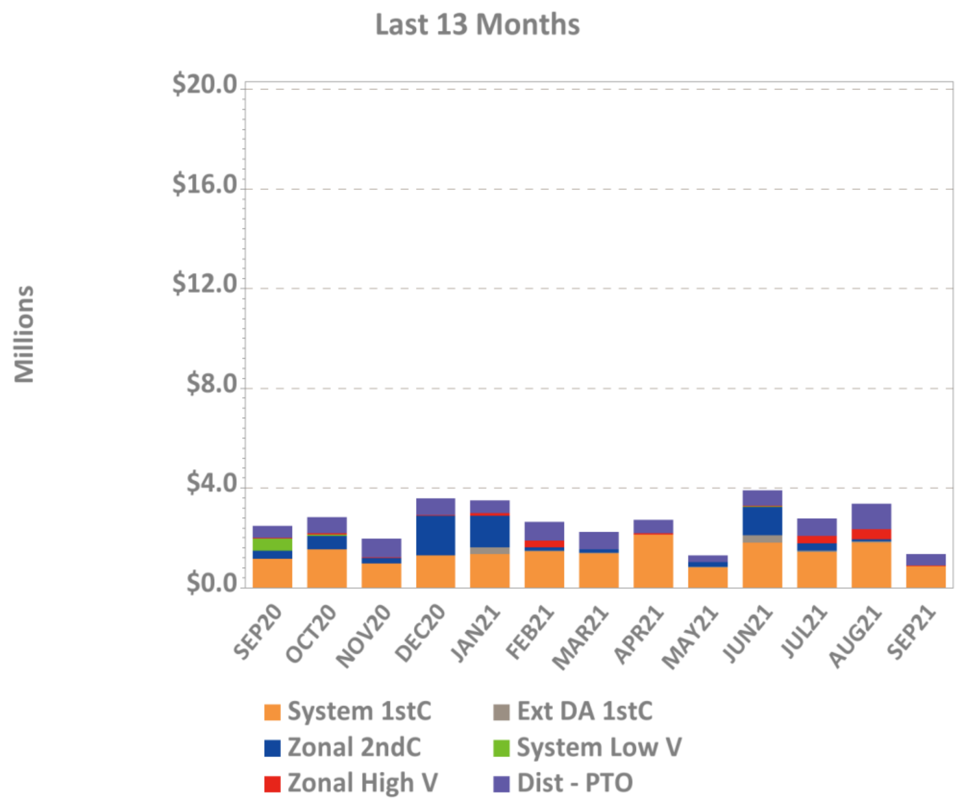
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



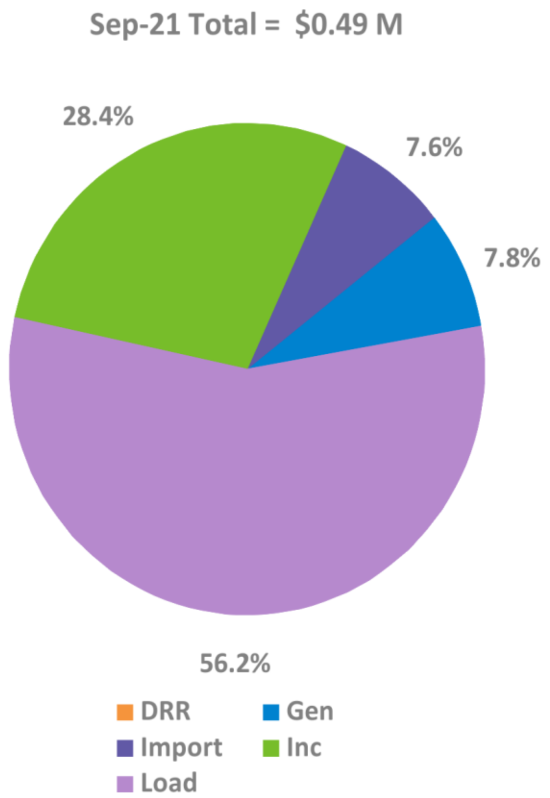
NCPC Charges by Allocation

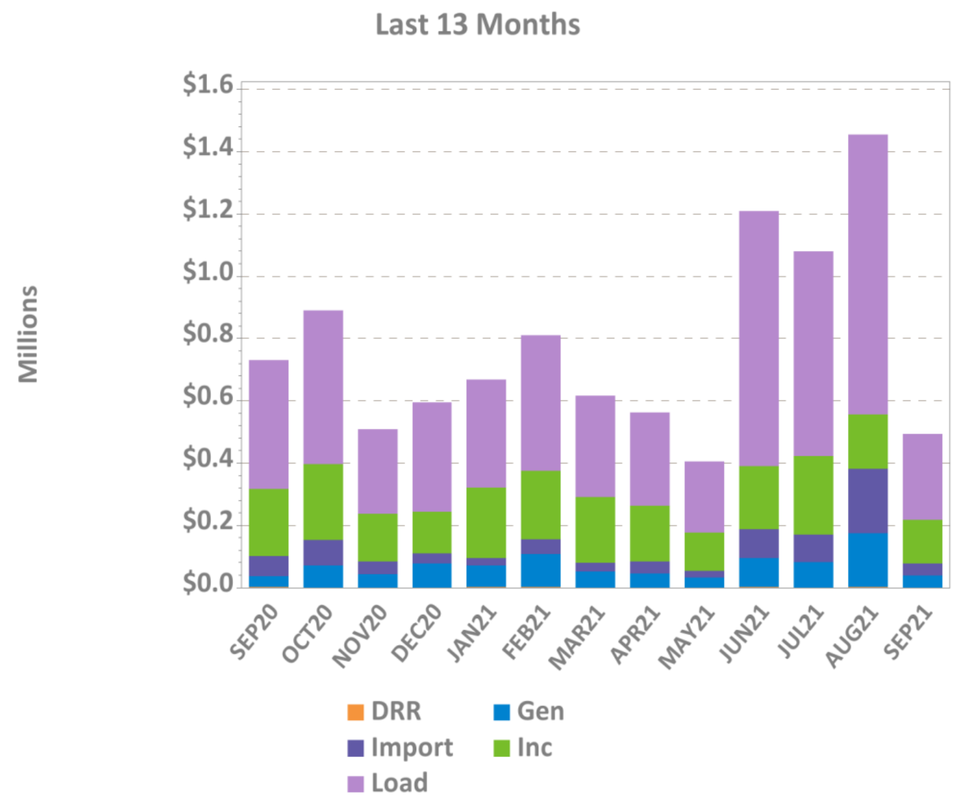




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

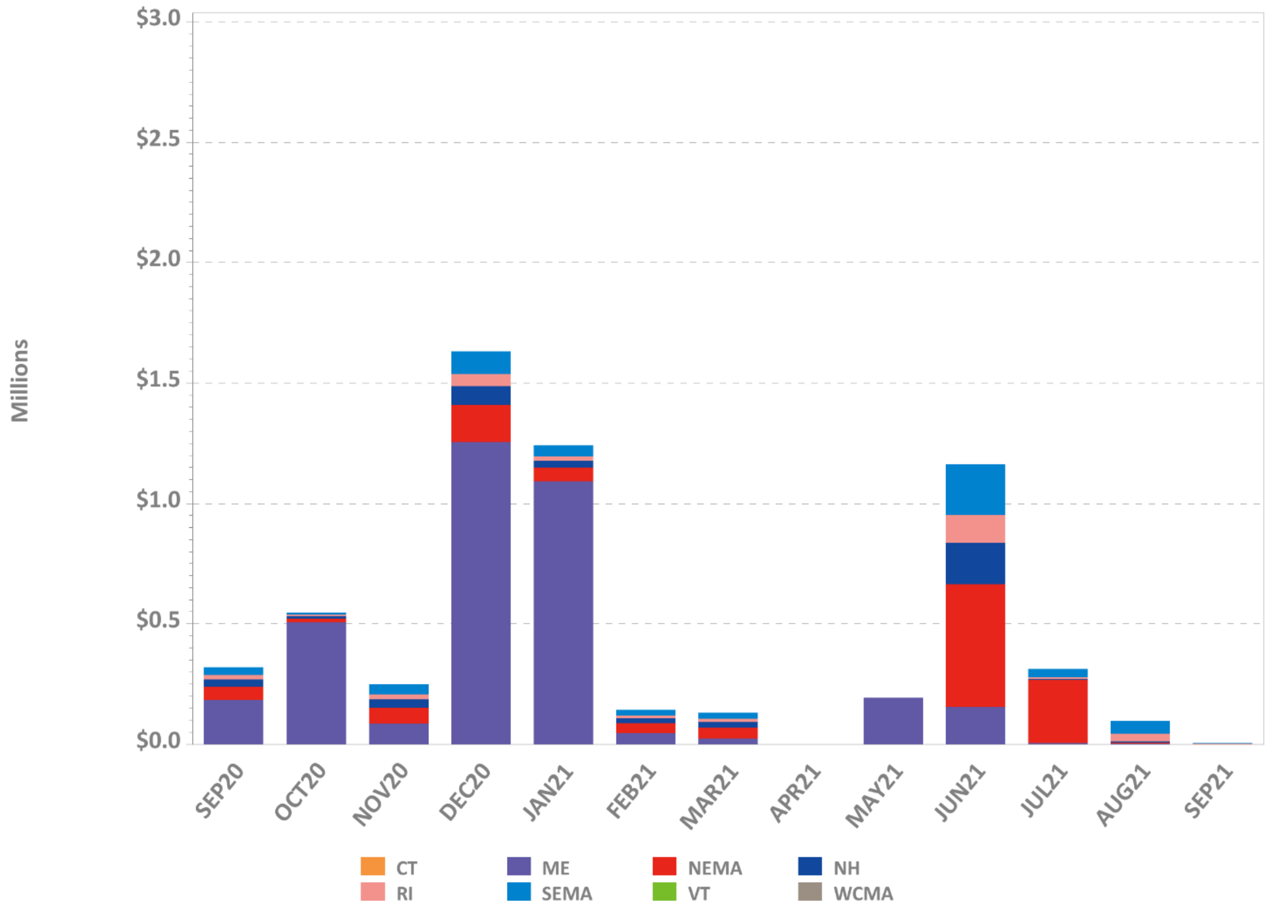
RT First Contingency Charges by Deviation Type





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

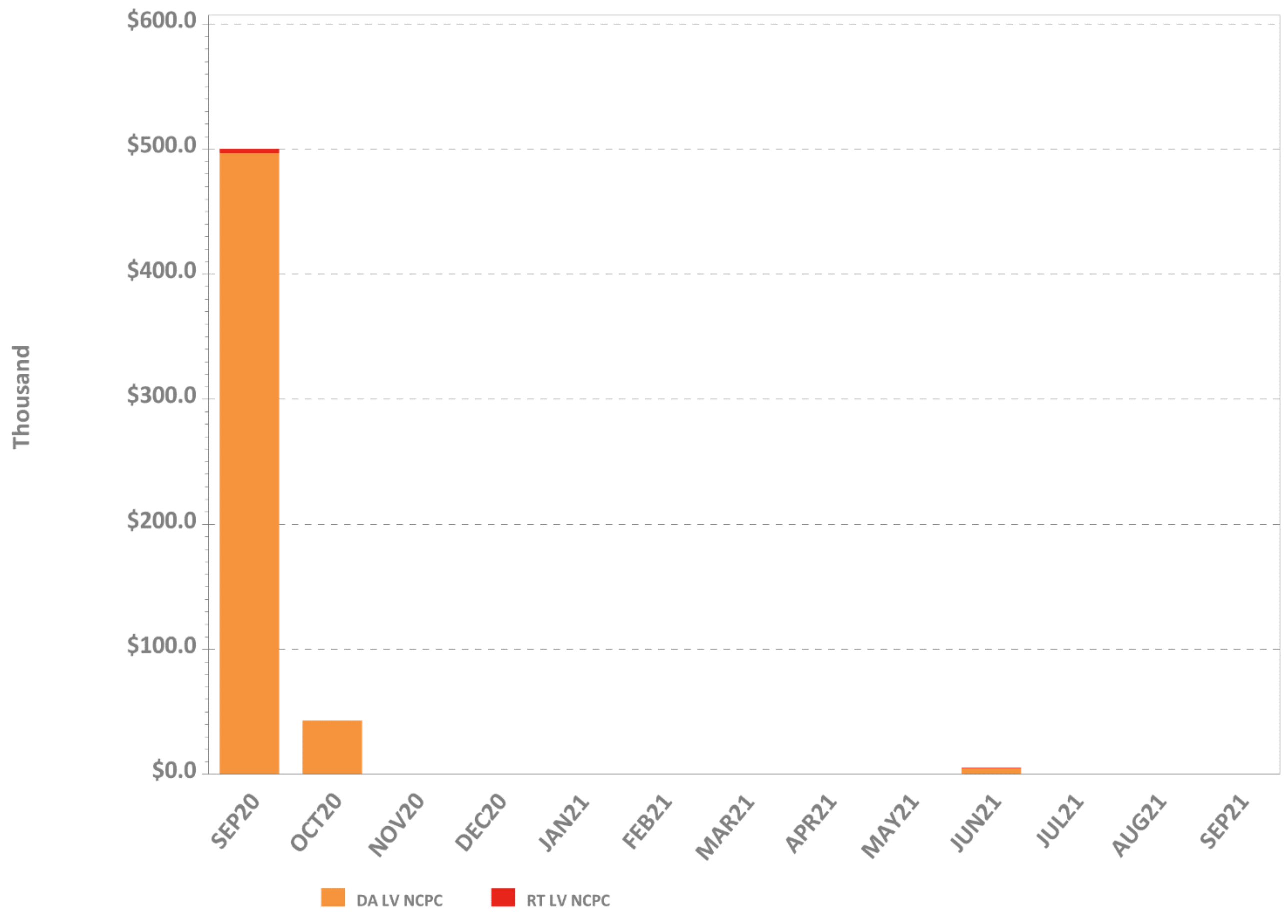
LSCPR Charges by Reliability Region



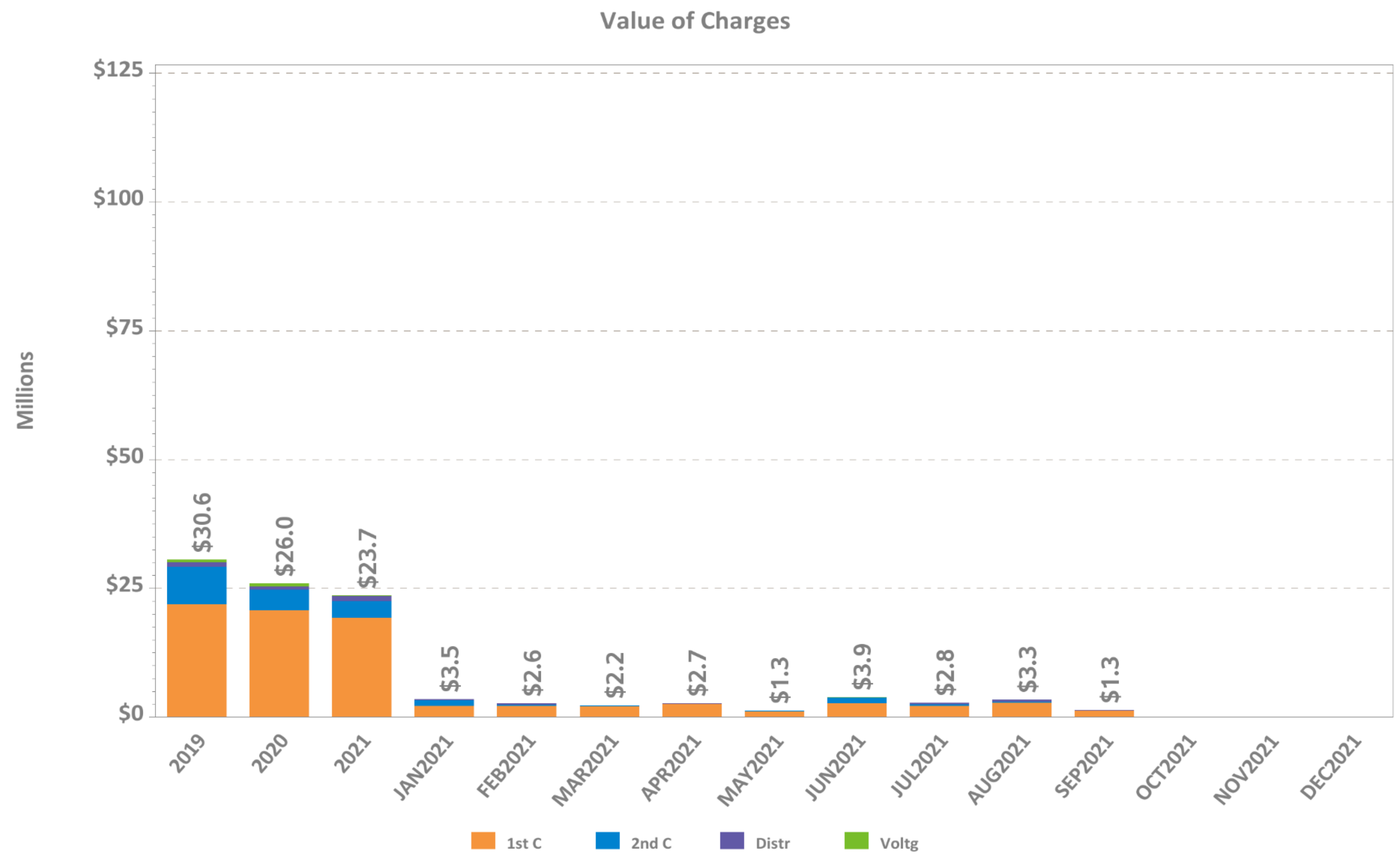
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

SEMA – Southeast Massachusetts Region
WCMA – Western/Central Massachusetts Region
NEMA – Northeast Massachusetts Region

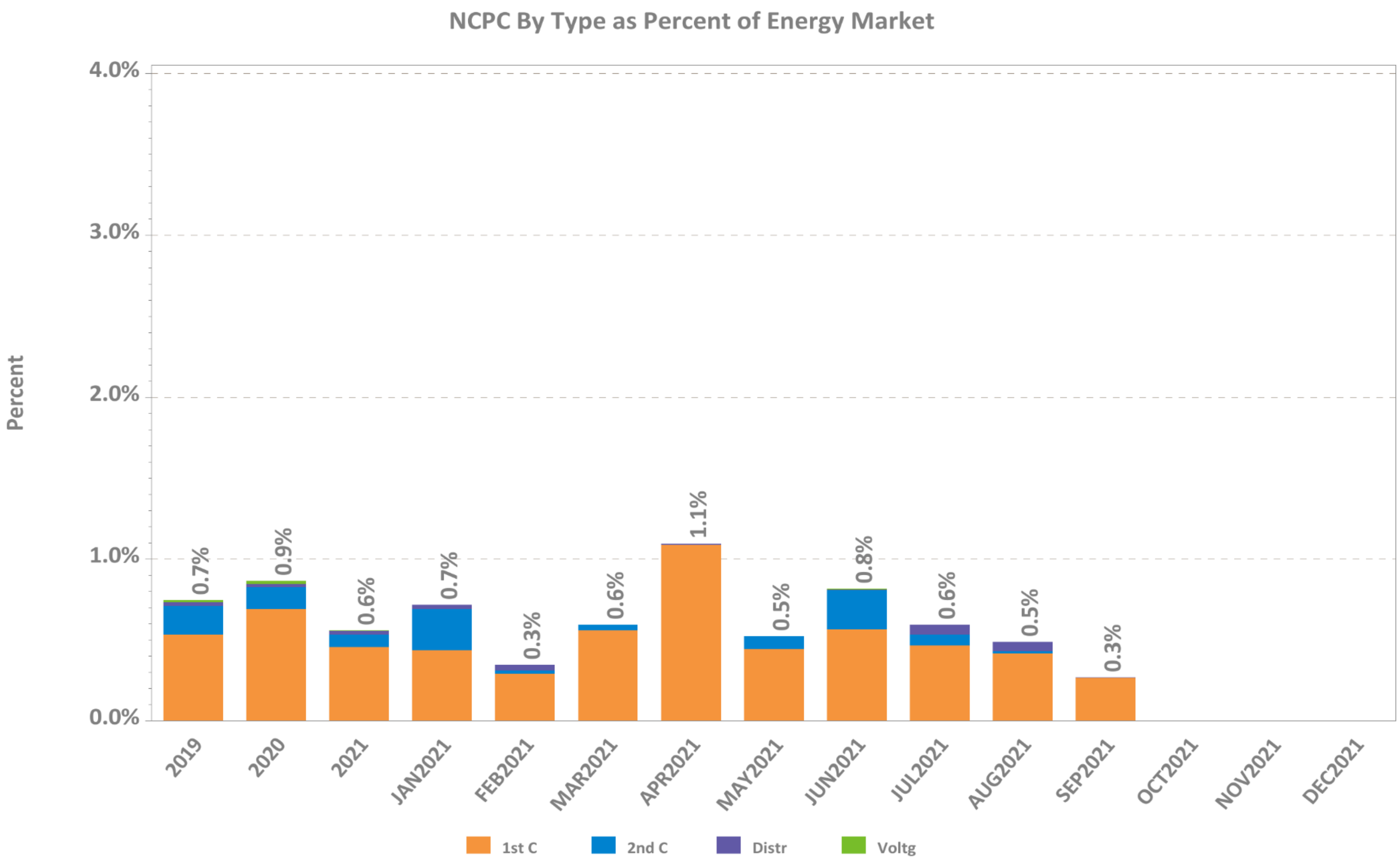
NCPC Charges for Voltage Support and High Voltage Control



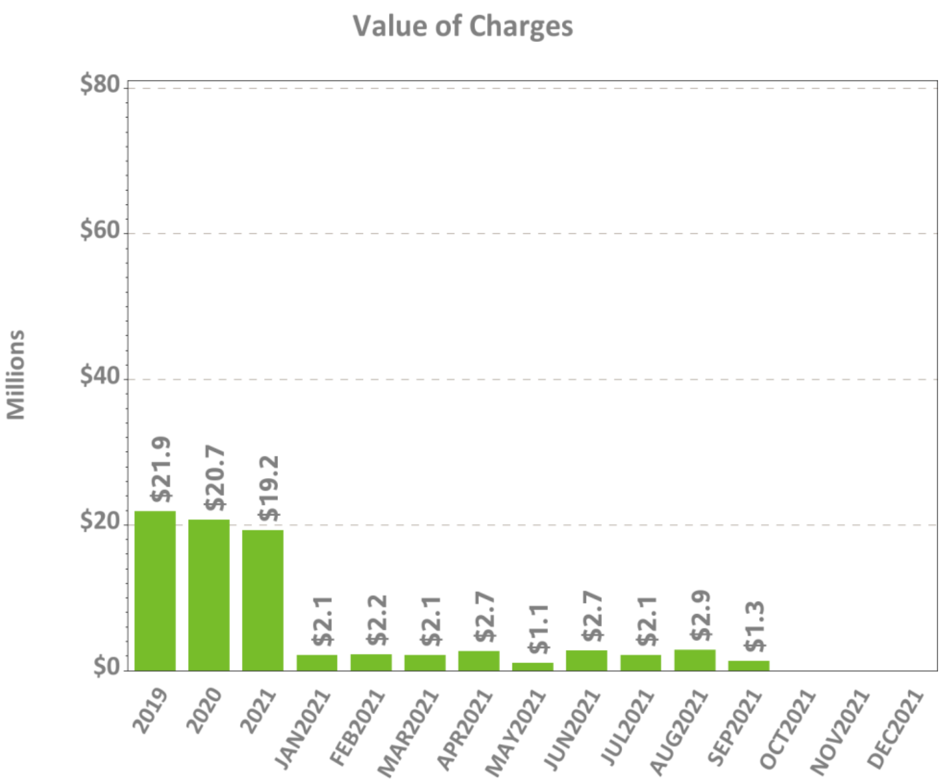
NCPC Charges by Type

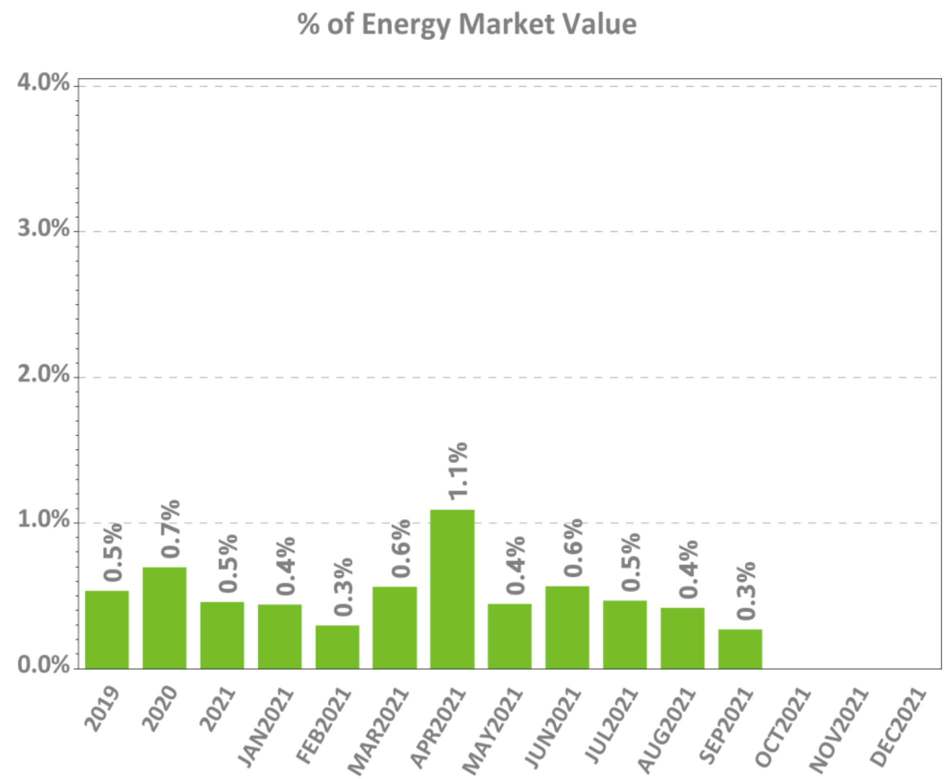


NCPC Charges as Percent of Energy Market



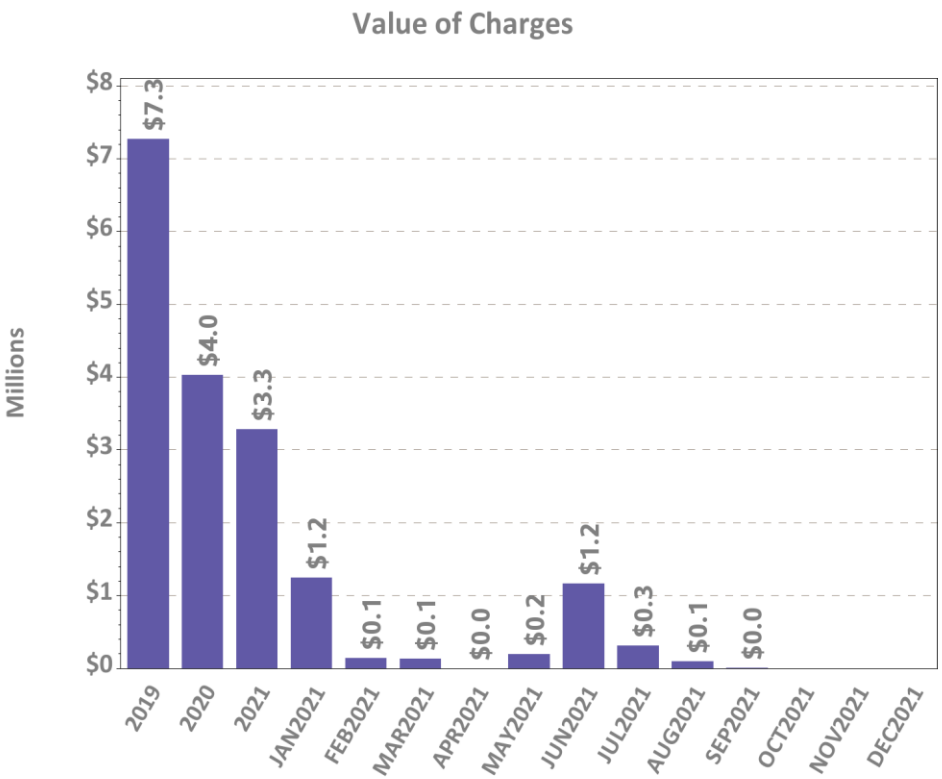
First Contingency NCPC Charges

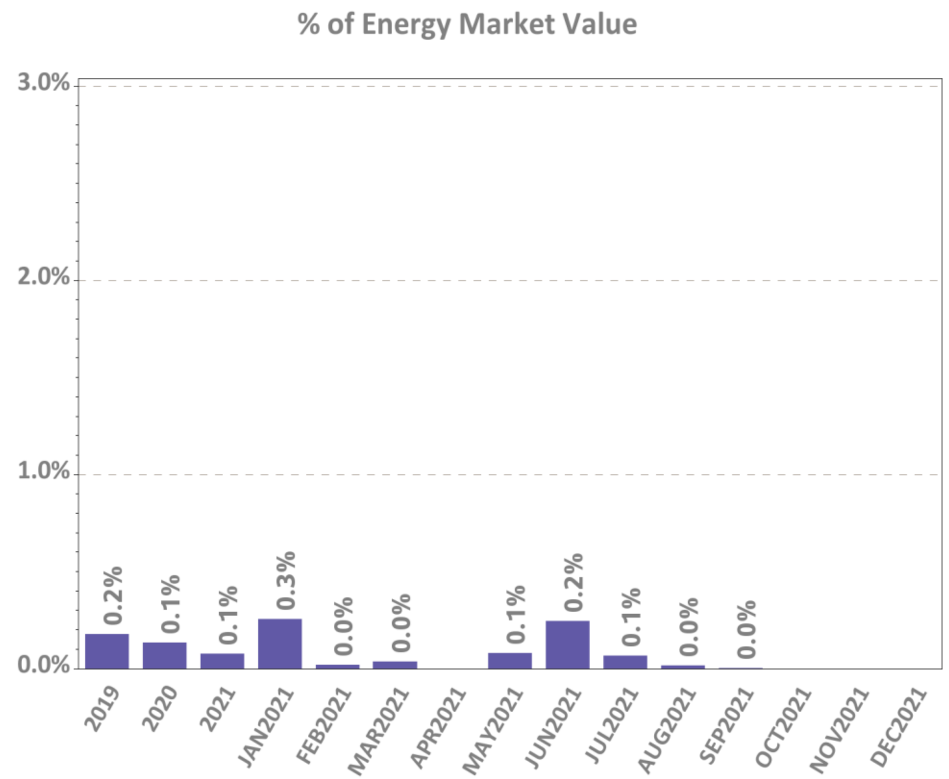




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

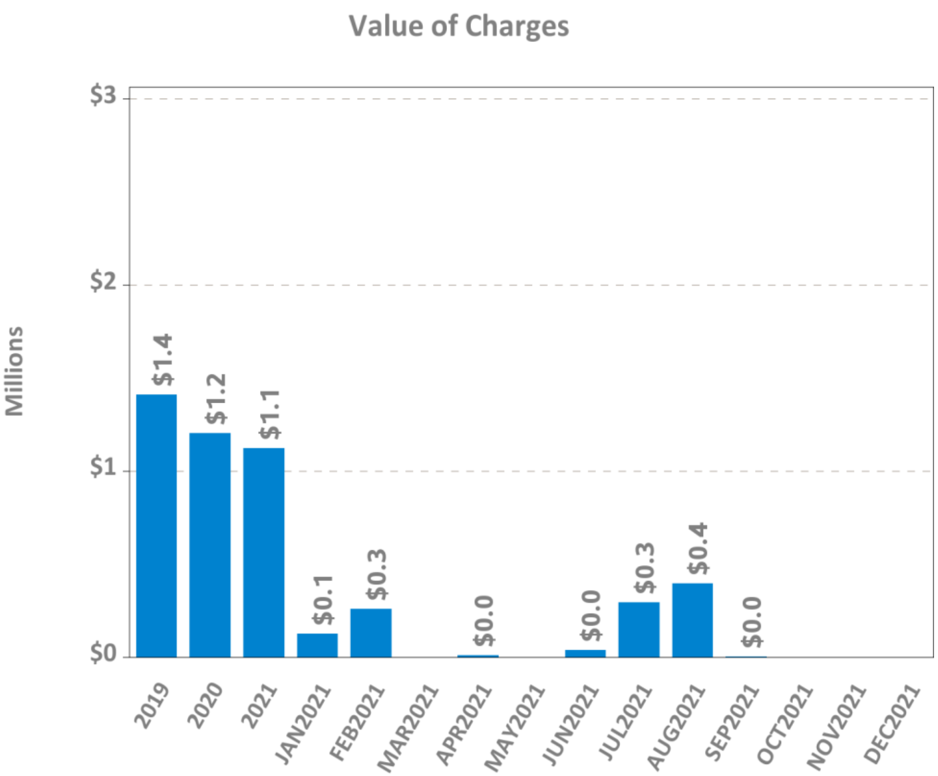
Second Contingency NCPC Charges

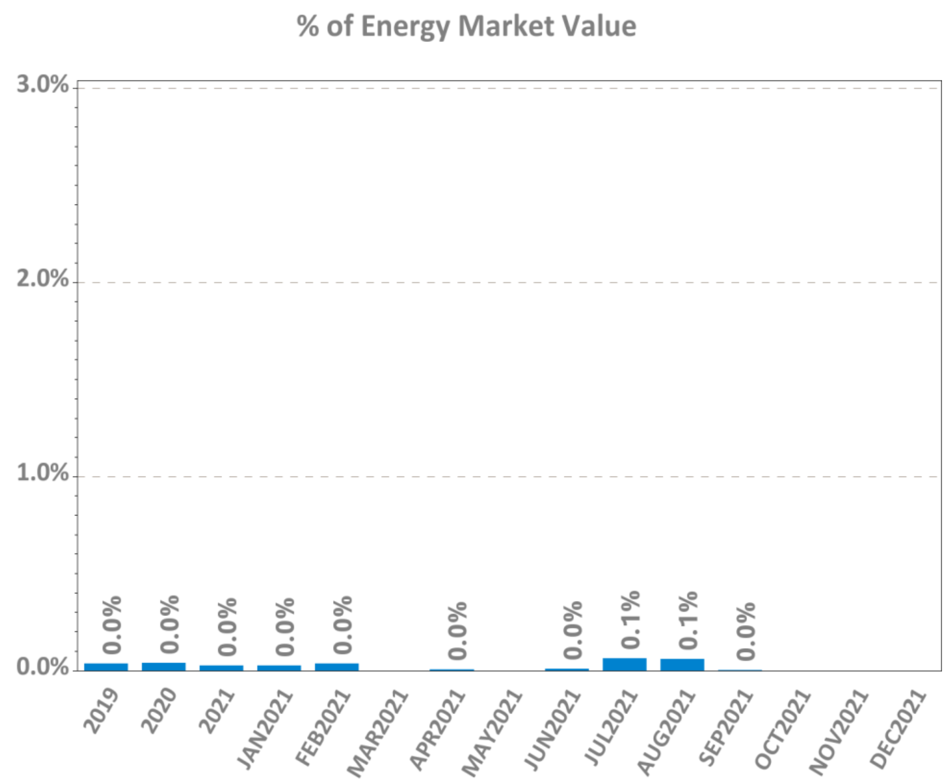




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

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

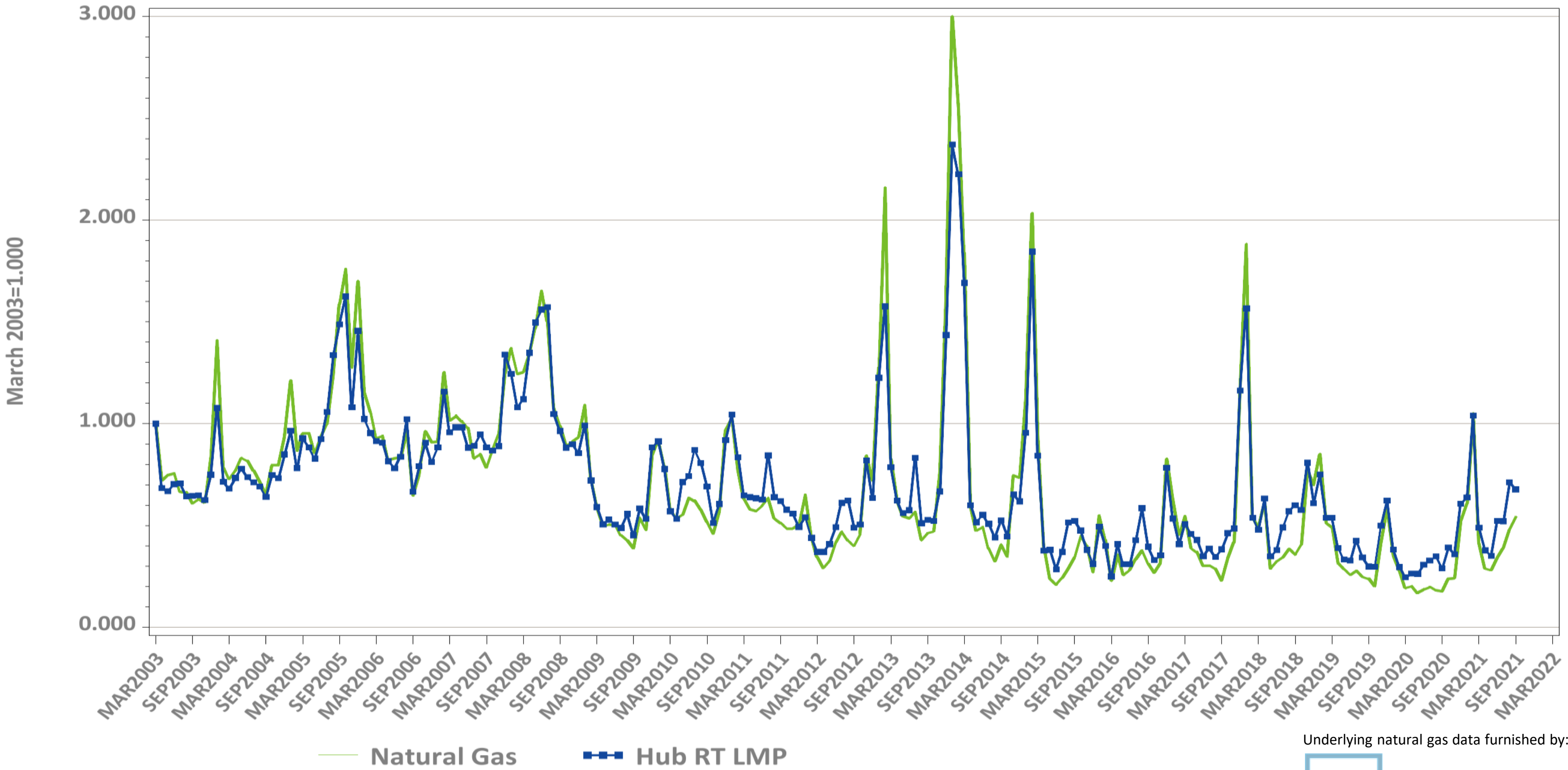
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 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%
Year 2020	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$23.62	$22.59	$23.27	$23.50	$22.76	$23.27	$23.57	$23.30	$23.32
Real-Time	$23.62	$22.91	$23.23	$23.54	$22.90	$23.29	$23.56	$23.37	$23.38
RT Delta %	0.0%	1.4%	-0.2%	0.2%	0.6%	0.1%	-0.1%	0.3%	0.3%

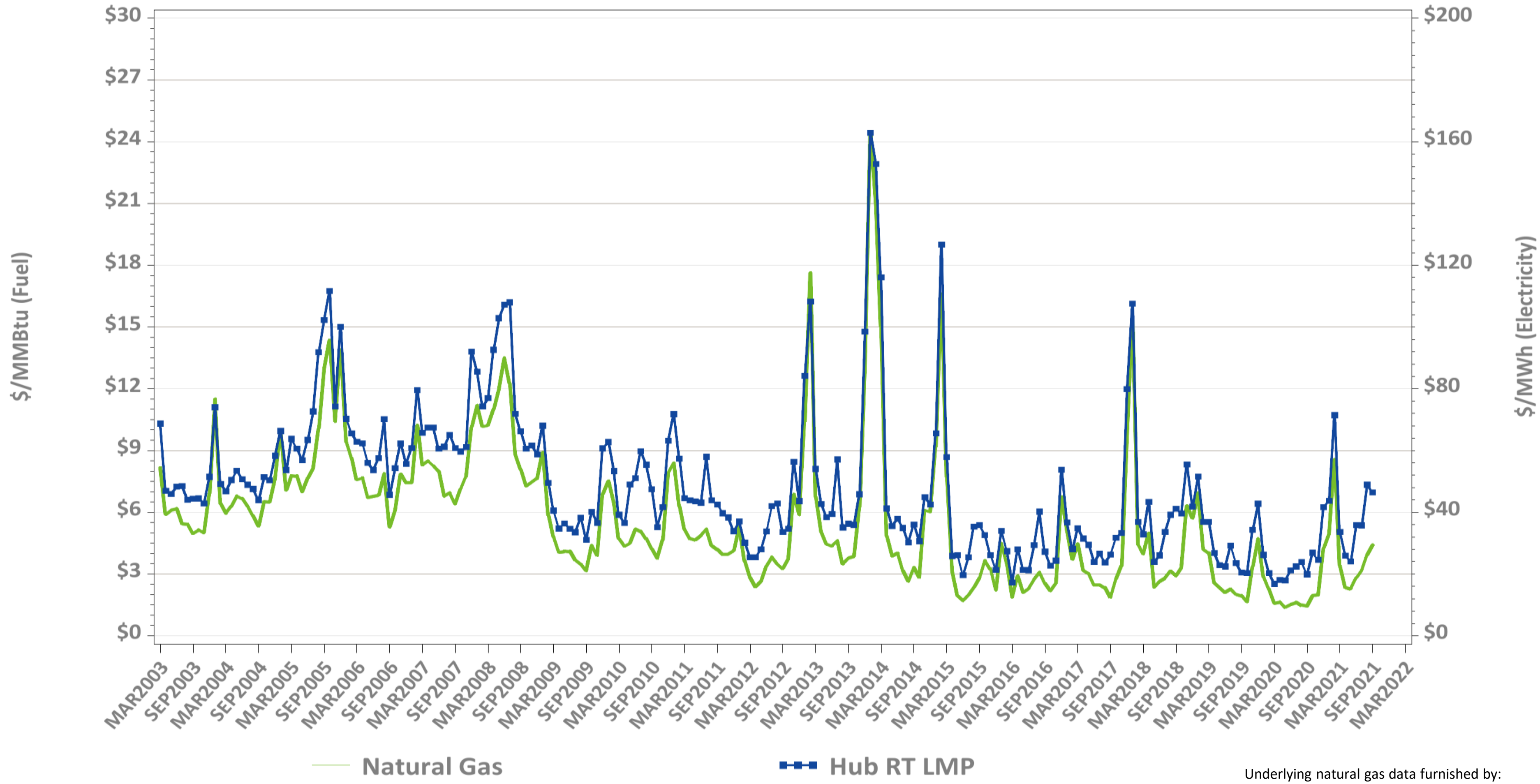
September-20	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$21.07	$19.41	$21.14	$21.00	$19.80	$20.51	$20.84	$20.43	$20.46
Real-Time	$20.17	$19.41	$20.59	$20.25	$19.68	$19.64	$19.93	$19.88	$19.88
RT Delta %	-4.3%	0.0%	-2.6%	-3.6%	-0.6%	-4.3%	-4.4%	-2.7%	-2.9%
September-21	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$48.96	$46.85	$46.45	$48.05	$47.23	$47.58	$48.61	$48.02	$48.01
Real-Time	$46.94	$45.74	$45.07	$46.60	$45.81	$45.94	$46.85	$46.50	$46.48
RT Delta %	-4.1%	-2.4%	-3.0%	-3.0%	-3.0%	-3.4%	-3.6%	-3.2%	-3.2%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	132.4%	141.5%	119.7%	128.8%	138.5%	131.9%	133.2%	135.0%	134.6%
Yr over Yr RT	132.8%	135.7%	118.9%	130.1%	132.7%	133.9%	135.1%	133.9%	133.8%

Monthly Average Fuel Price and RT Hub LMP Indexes



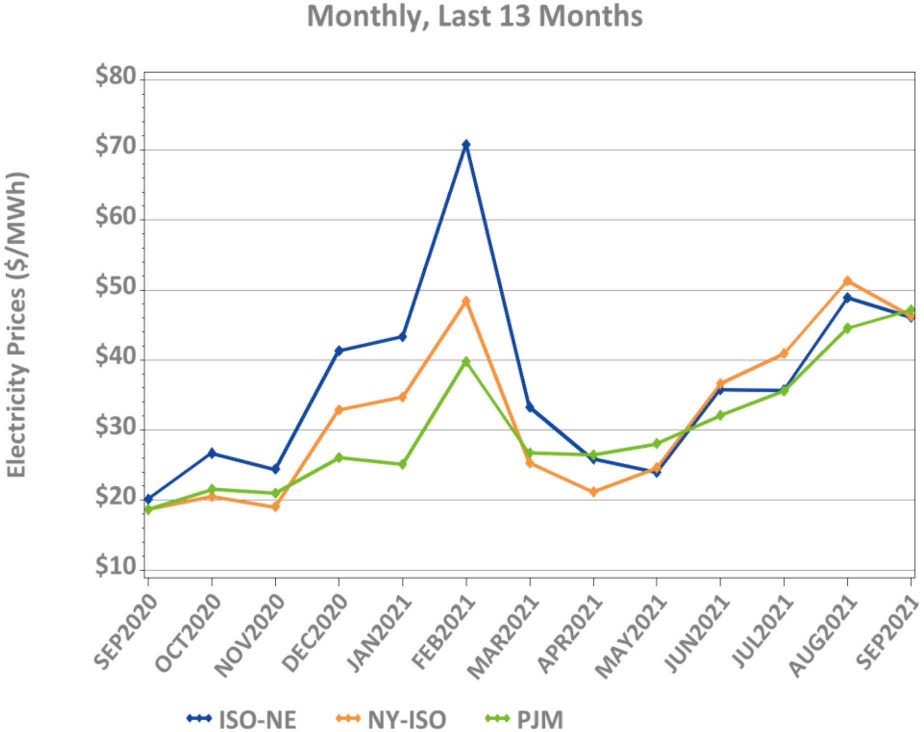
Underlying natural gas data furnished by: ICE Global markets in clear view

Monthly Average Fuel Price and RT Hub LMP

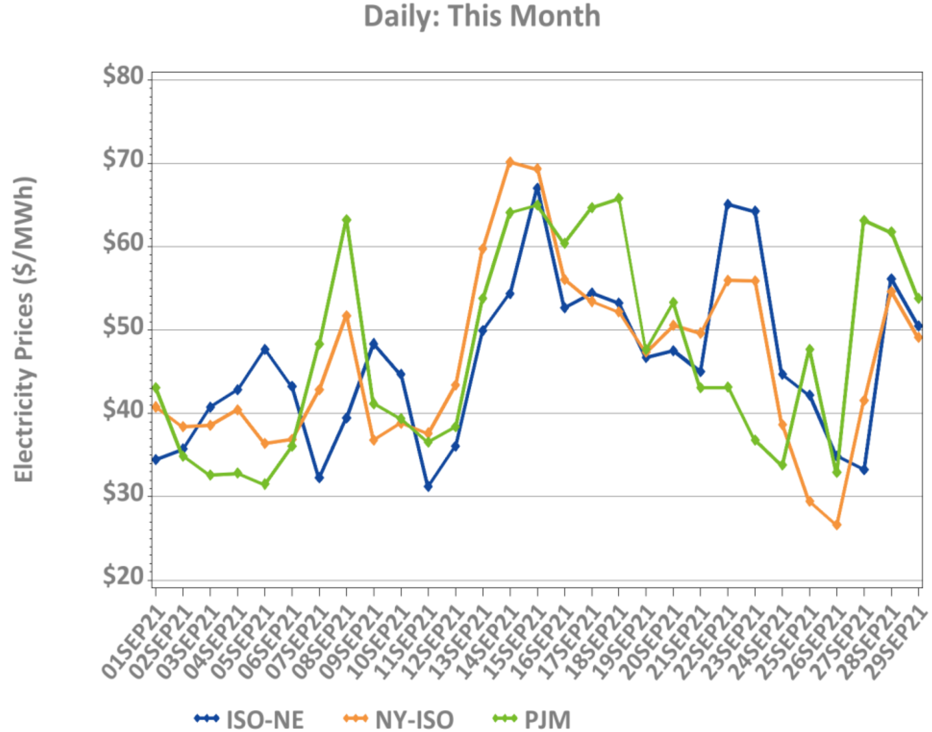


Underlying natural gas data furnished by: ICE Global markets in clear view

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

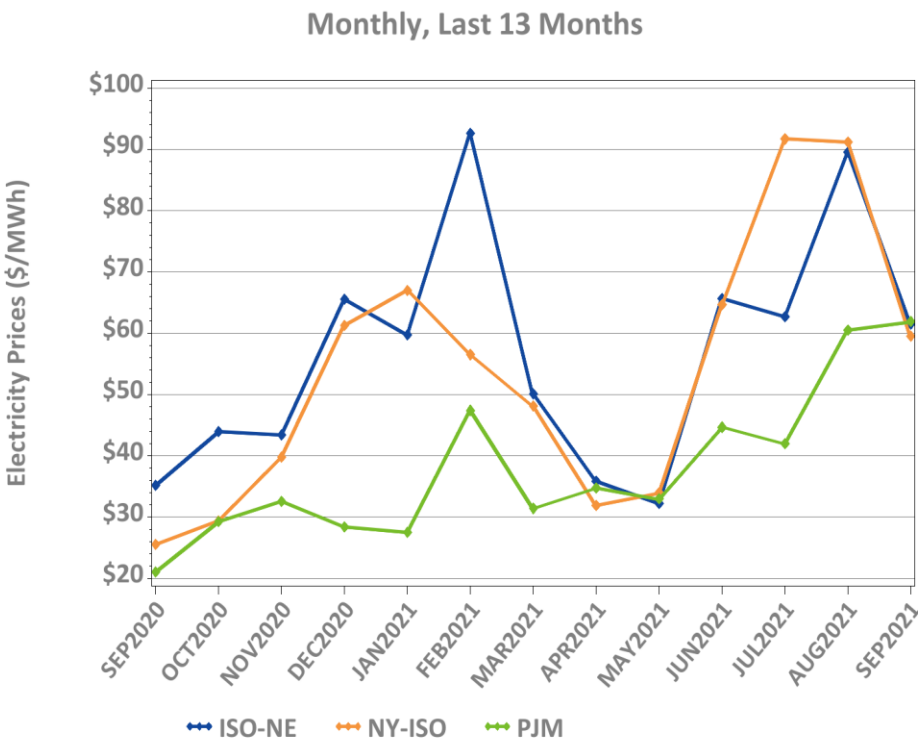


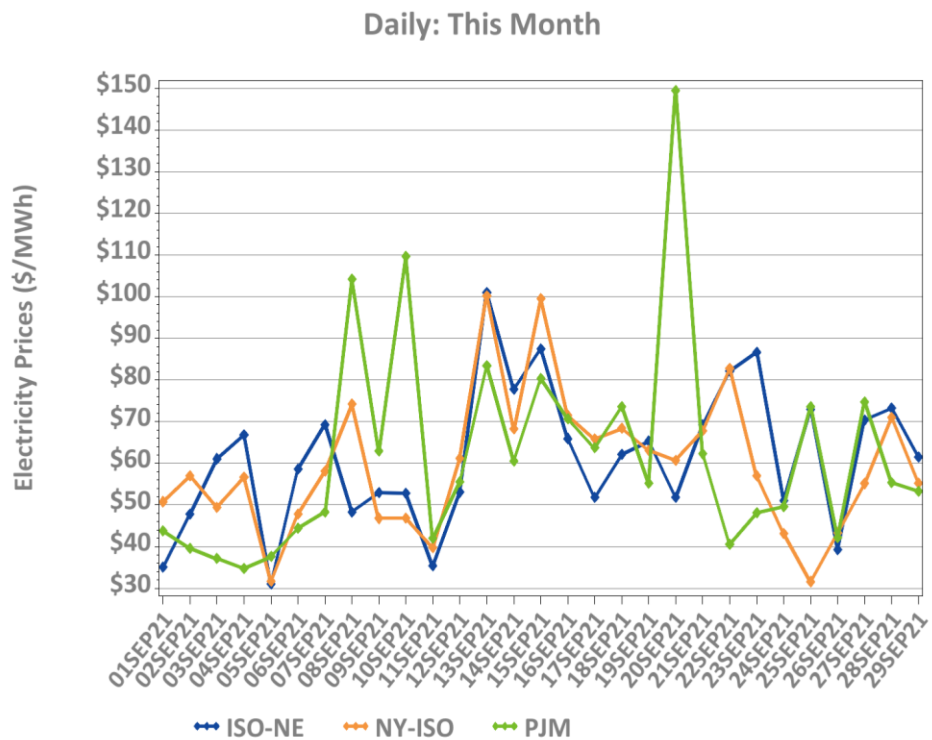
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

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





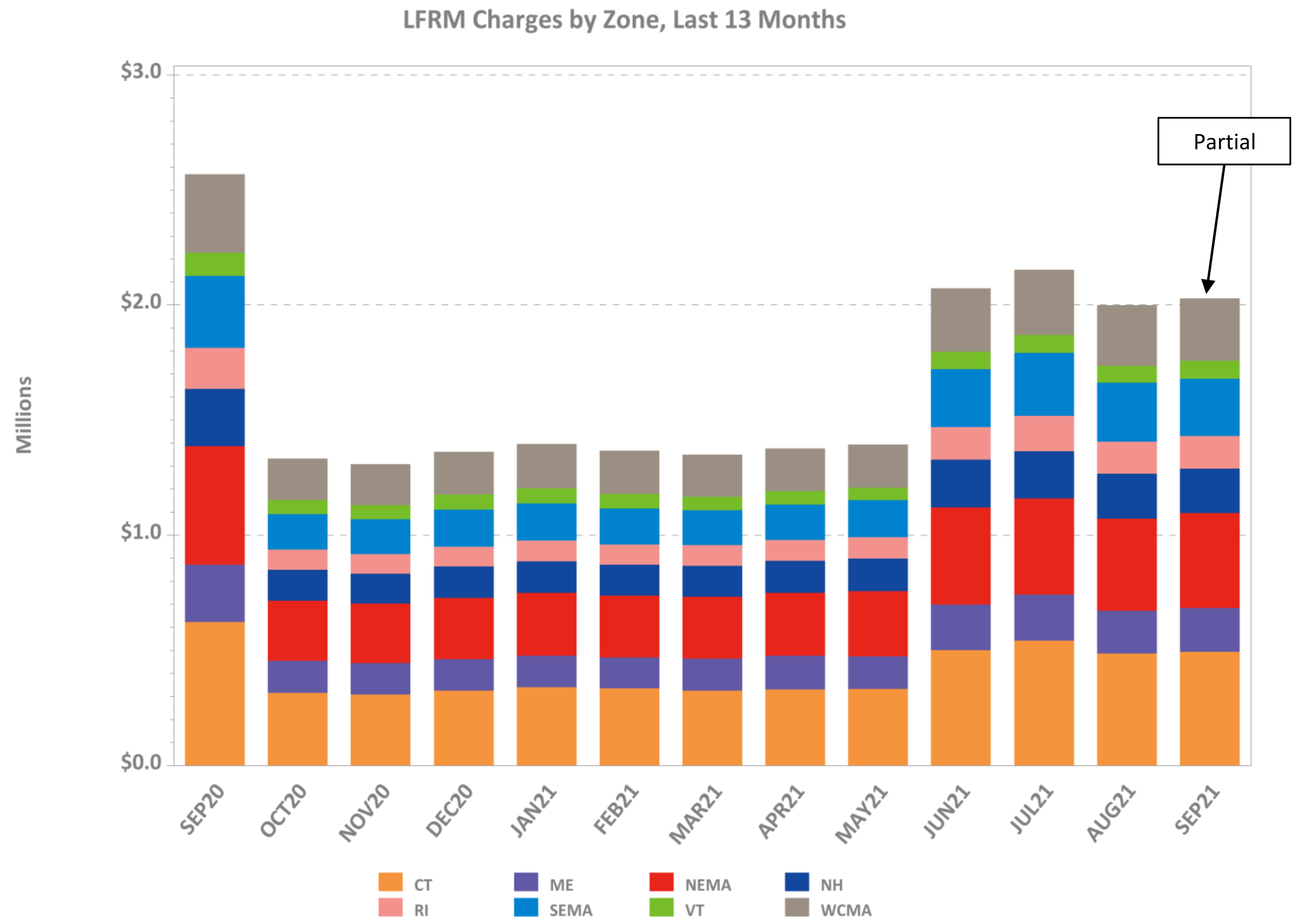
*Forecasted New England daily peak hours reflected

Reserve Market Results – September 2021

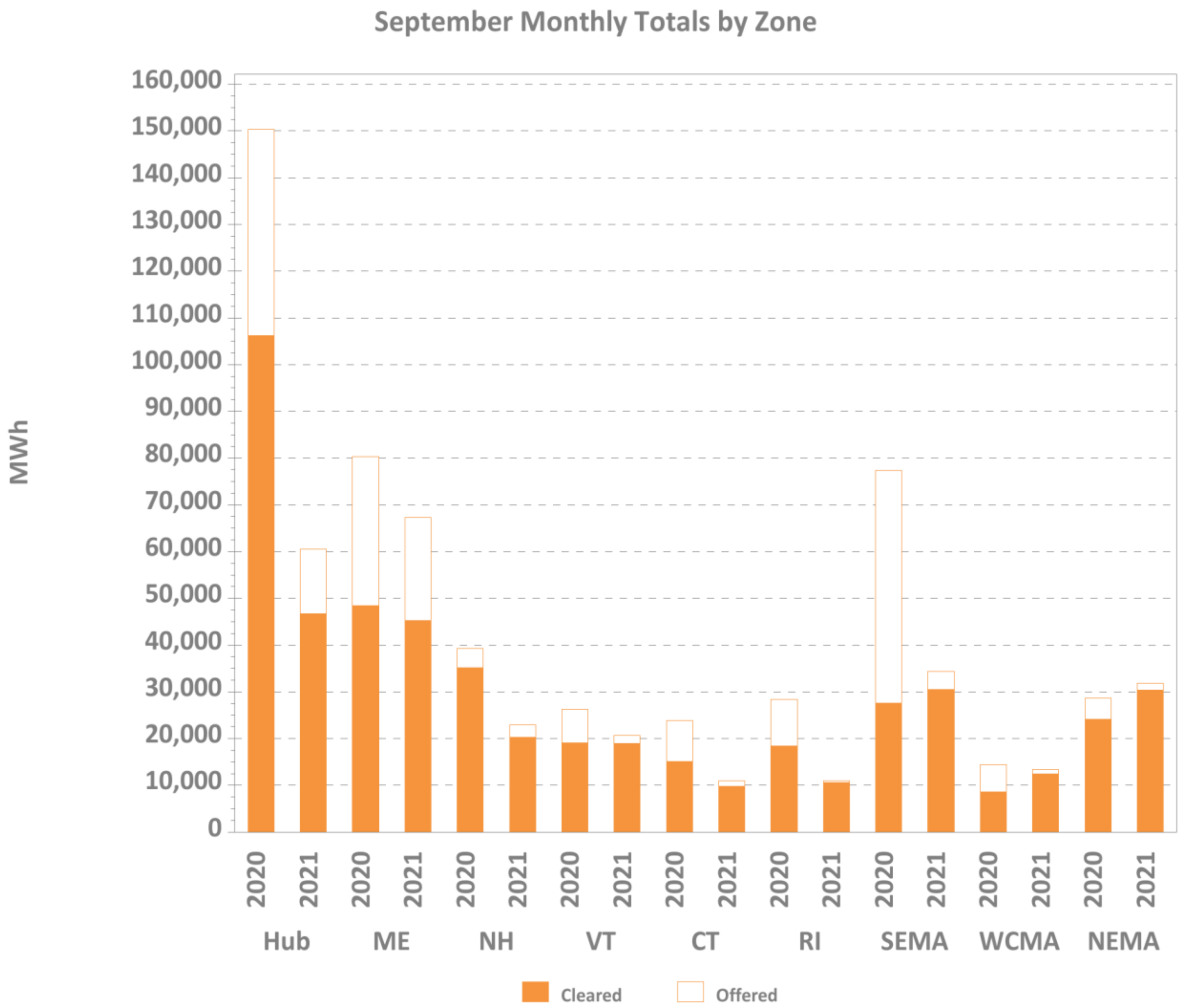
- Maximum potential Forward Reserve Market payments of $2.2M were reduced by credit reductions of $53K, failure-to-reserve penalties of $80K and no failure-to-activate penalties, resulting in a net payout of $2M or 95% of maximum
  - Rest of System: $1.56M/1.69M (92%)
  - Southwest Connecticut: $0.05M/0.05M (99%)
  - Connecticut: $0.4M/0.41M (99%)
  - NEMA: $0M/0M (100%)
- $361K total Real-Time credits were not reduced by any Forward Reserve Energy Obligation Charges for a net of $361K in Real-Time Reserve payments
  - Rest of System: 199 hours, $262K
  - Southwest Connecticut: 199 hours, $37K
  - Connecticut: 199 hours, $41K
  - NEMA: 199 hours, $21K

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.

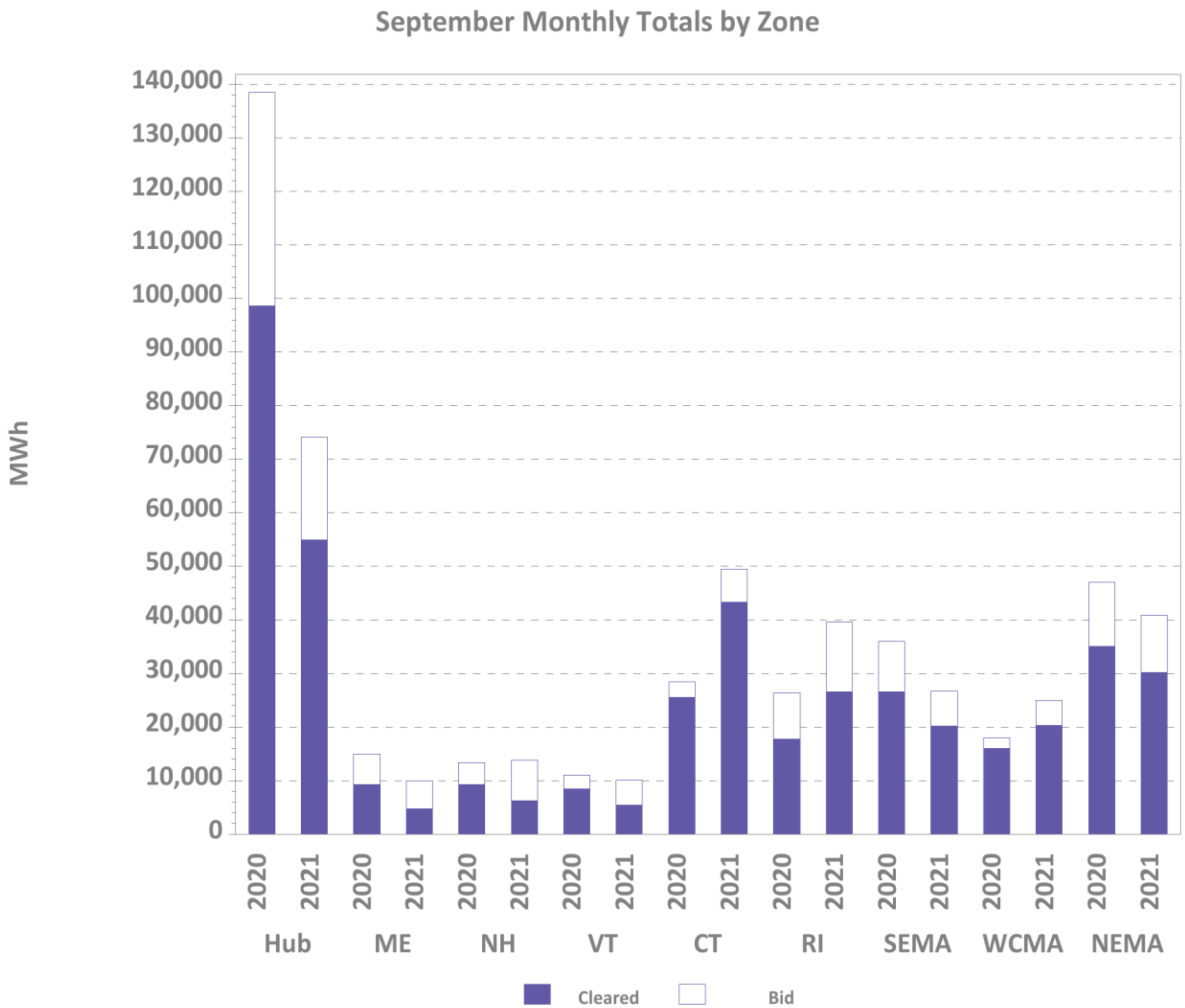
LFRM Charges to Load by Load Zone ($)



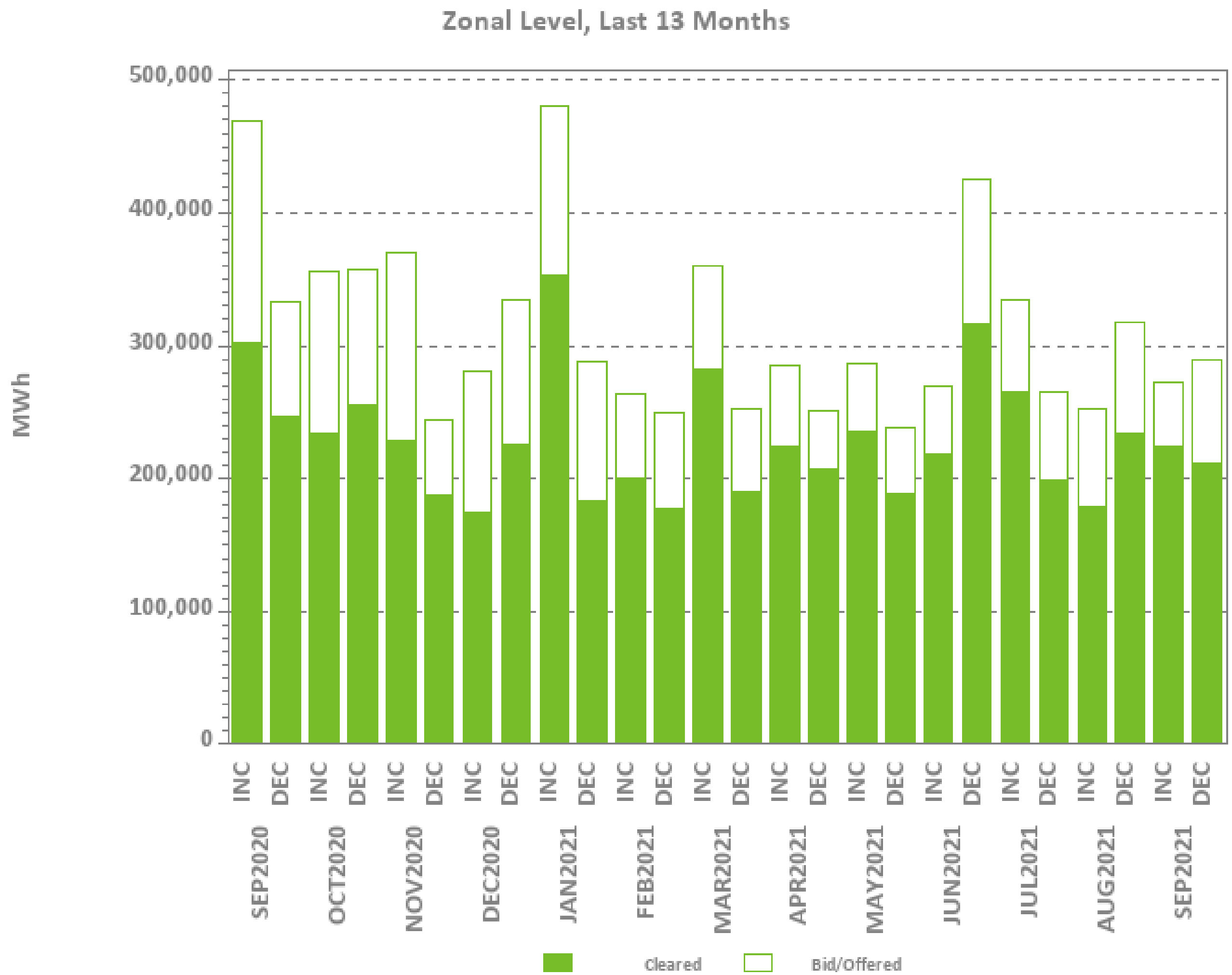
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

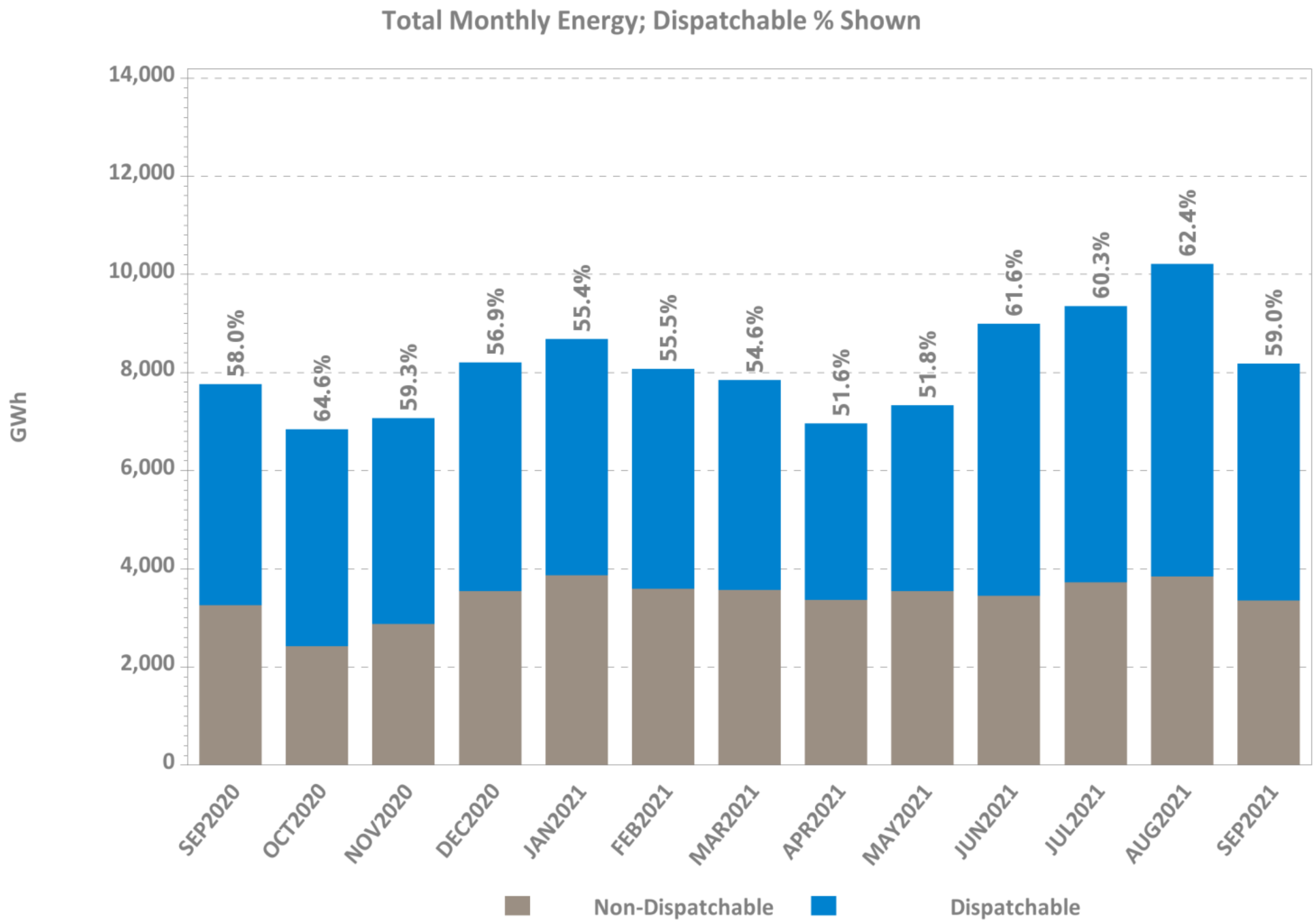


Total Increment Offers and Decrement Bids



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)

Regional System Plan (RSP)

- The near-final draft of RSP21 was posted with the October 6 Public Meeting materials

Planning Advisory Committee (PAC)

- October 20 PAC Meeting Agenda Topics*
  - 2021 Economic Study: Future Grid Reliability Study Phase 1 - Ancillary Services Preliminary Results - Part 2
  - 2021 Economic Study: Future Grid Reliability Study Phase 1 - High Level Transmission Analysis - Preliminary Results
  - Updated Transmission Planning Technical Guide
  - SEMA/RI 2030 Minimum Load Needs Assessment Results
  - Transmission Owners Planning Advisory Committee (TOPAC) - Updated Local System Plans
    - New Hampshire Transmission
    - VELCO
    - Versant Power
    - UI/AVANGRID
    - National Grid
    - Eversource Energy

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

Transmission Planning for the Clean Energy Transition

- On 9/24/20 the ISO initiated discussions with the PAC about proposed refinements to study assumptions that better reflect long-term trends, such as increased amounts of distributed-energy resources (primarily solar PV), offshore wind generation, and battery energy storage
- A follow-up presentation at the 11/19/20 PAC meeting outlined a proposal for a pilot study, with the following goals:
  - Explore transmission reliability concerns that may result from various system conditions possible by 2030
  - Quantify trade-offs necessary between transmission system reliability/flexibility and transmission investment cost
  - Inform future discussions on transmission planning study assumptions
- An overview of the system conditions and dispatch assumptions for the pilot study was discussed at the 12/16/20 and 1/21/21 PAC meetings
- Results were discussed at the 6/16/21, 7/22/21, and 8/18/21 PAC meetings
- The ISO published draft revisions to the Transmission Planning Technical Guide reflecting these changes on 9/15/21
- Future testing will focus on transient stability modeling and performance criteria

Economic Studies

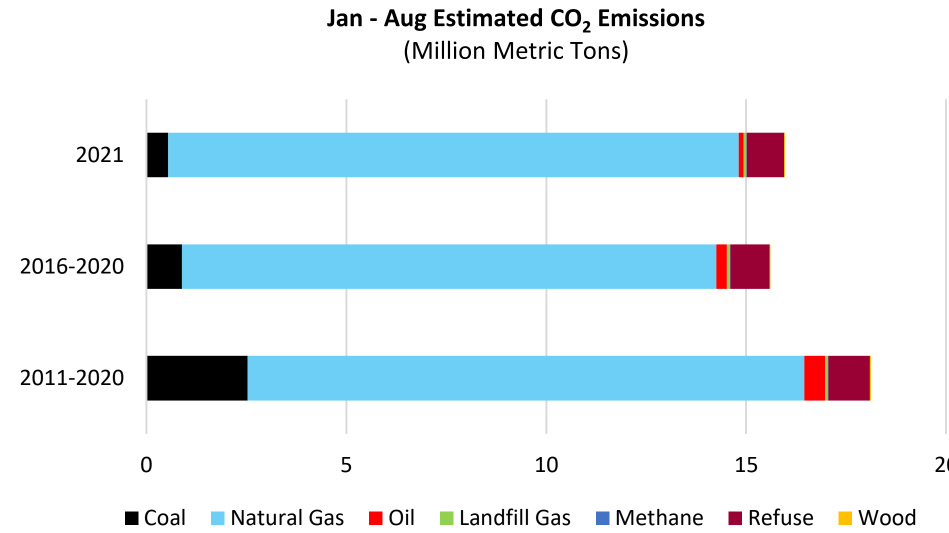
- 2020 Economic Study Request
  - Study proponent is National Grid
  - Study simulations are complete, and results have been presented to PAC
    - Draft report to be completed by the end of 2021
- 2021 Economic Study Request
  - Also known as Future Grid Reliability Study – Phase 1 (FGRS)
  - Study proponent is NEPOOL
    - Preliminary production cost results were discussed at the special September 17 PAC meeting and joint MC/RC meetings
      - The ISO is working on refining the scenario matrix and will present to the MC/RC for approval before finishing the final runs
    - Preliminary ancillary services analyses results were presented at the September 22 PAC meeting and, after confirmation of scenario adjustments at the MC/RC meeting, the remaining preliminary ancillary services analyses results will be presented at the October 20 PAC meeting

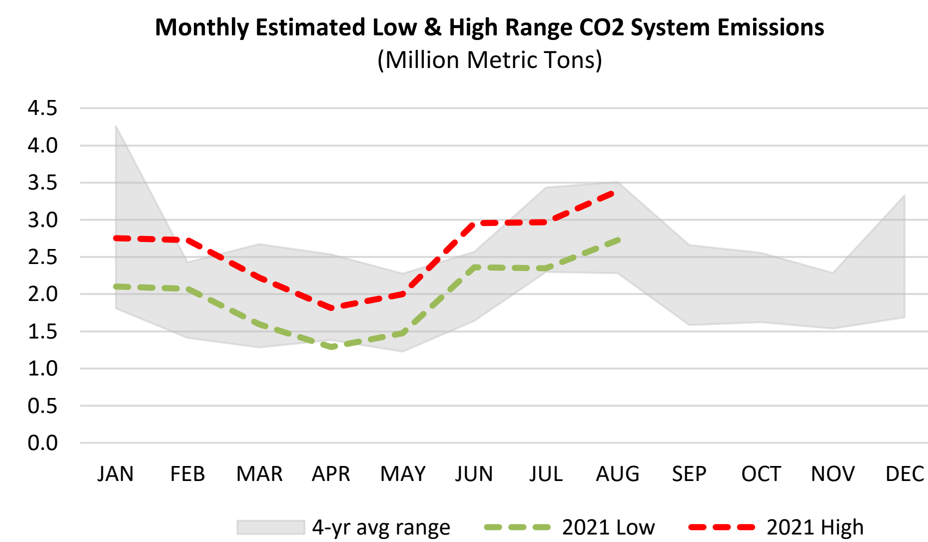
Future Grid Reliability Study (FGRS)

- Phase 1
  - Studies include: Production Cost Simulations; Ancillary Services Simulations; Resource Adequacy Screen; and Probabilistic Resource Availability Analysis
  - Framework Document and supporting assumptions table, which describe study scenarios and objectives, have been developed by stakeholders
  - Phase 1 work was submitted as the only 2021 economic study
  - Production Cost Simulations preliminary results were presented at the special September 17 PAC meeting
  - Ancillary Services Simulation initial results were presented at the September 22 PAC meeting and remaining results will be presented at the October PAC meeting
- Phase 2
  - Studies include: Revenue Sufficiency Analysis and Transmission Security
  - Studies will be delayed as the Pathways and 2050 Transmission studies are further defined
  - Studies likely to be performed by a consultant
  - Embellishment of the study scope continues at the MC/RC

Environmental Matters – Shift in Power System Emission Trends

- 2021 estimated CO_2 emissions running 102% of 5-year averages and 88% of 10-year averages for the same period (January - August)
  - Natural-gas CO_2 emissions 107% of 5-year averages and 102% of 10-year averages
  - CO_2 emissions from all other emitting fuel categories declined compared to 5- and 10-year averages
- January - August 2021 estimated system CO_2 emissions range between 15.9 and 20.8 million metric tons (MMT)
- January - August 4-year average (2017-2020) CO_2 emissions range between 13.3 and 23.6 MMT



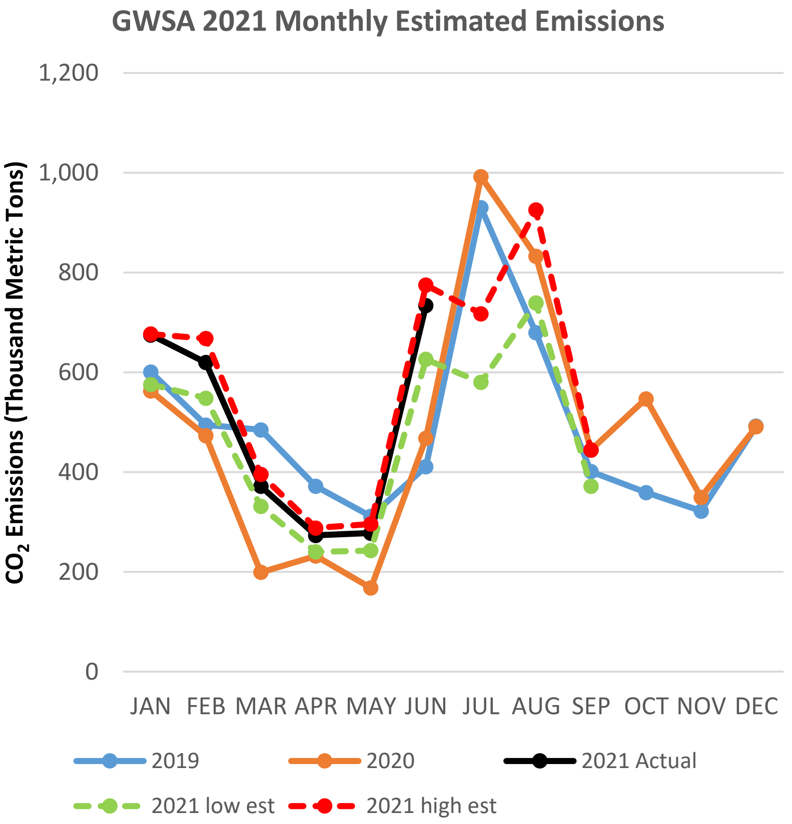


Environmental Matters – Massachusetts CO_2 Generator Emissions Cap

2021 CO_2 GWSA Emissions Trending Lower

- As of 9/26/21, estimated GWSA CO_2 emissions range between 4.25 and 5.18 MMT:
  - 51% to 63% of the 8.23 MMT 2021 cap
- 9/15/21 GWSA auction cleared at $10 per metric ton. Using latest clearing price, IMM estimated compliance costs by fuel type (based average GWSA emission/heat rates):
  - No. 2 fuel oil - $8.54/MWh
  - No. 6 fuel oil - $8.29/MWh
  - Natural gas - $2.39/MWh
- Affected generators have access to banked allowances in excess of expected 2021 emissions

2019-2021 Estimated Monthly Emissions (Thousand Metric Tons)



GWSA - Global Warming Solutions Act

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.

Greater Boston Projects

Status as of 9/27/2021

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1213, 1220, 1365	Install new 345 kV line from Scobie to Tewksbury	Dec-17	4
1527, 1528	Reconductor the Y-151 115 kV line from Dracut Junction to Power Street	Apr-17	4
1212, 1549	Reconductor the M-139 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
1549	Reconductor the N-140 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
1260	Reconductor the F-158N 115 kV line from Wakefield Junction to Maplewood and associated work at Maplewood	Dec-15	4
1550	Reconductor the F-158S 115 kV line from Maplewood to Everett	Jun-19	4
1551, 1552	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-22	3*
1329	Refurbish X-24 69 kV line from Millbury to Northboro Road	Dec-15	4
1327	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 9/27/2021

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1330	Separate X-24 and E-157W DCT	Dec-18	4
1363	Separate Q-169 and F-158N DCT	Dec-15	4
1637, 1640	Reconductor M-139/211-503 and N-140/211-504 115 kV lines from Pinehurst to North Woburn tap	May-17	4
1516	Install new 115 kV station at Sharon to segment three 115 kV lines from West Walpole to Holbrook	Sep-20	4
965	Install third 115 kV line from West Walpole to Holbrook	Sep-20	4
1558	Install new 345 kV breaker in series with the 104 breaker at Stoughton	May-16	4
1199	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
1335	Install a new 115 kV line from Sudbury to Hudson	Dec-23	2

Greater Boston Projects, cont.

Status as of 9/27/2021

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1336	Replace 345/115 kV autotransformer, 345 kV breakers, and 115 kV switchgear at Woburn	Dec-19	4
1553	Install a 345 kV breaker in series with breaker 104 at Woburn	Jun-17	4
1337	Reconfigure Waltham by relocating PARs, 282-507 line, and a breaker	Dec-17	4
1339	Upgrade 533-508 115 kV line from Lexington to Hartwell and associated work at the stations	Aug-16	4
1521	Install a new 115 kV 54 MVAR capacitor bank at Newton	Dec-16	4
1522	Install a new 115 kV 36.7 MVAR capacitor bank at Sudbury	May-17	4
1352	Install a second Mystic 345/115 kV autotransformer and reconfigure the bus	May-19	4
1353	Install a 115 kV breaker on the East bus at K Street	Jun-16	4
1354, 1738	Install 115 kV cable from Mystic to Chelsea and upgrade Chelsea 115 kV station to BPS standards	Jul-21	4
1355	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	Mar-21	4

Greater Boston Projects, cont.

Status as of 9/27/2021

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1356	Install a second 115 kV cable from Mystic to Woburn to create a bifurcated 211-514 line	May-22	3
1357	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
1518	Upgrade Kingston to create a second normally closed 115 kV bus tie and reconfigure the 345 kV switchyard	Mar-19	4
1519	Relocate the Chelsea capacitor bank to the 128-518 termination postion	Dec-16	4

Greater Boston Projects, cont.

Status as of 9/27/2021

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1520	Upgrade North Cambridge to mitigate 115 kV 5 and 10 stuck breaker contingencies	Dec-17	4
1643	Install a 200 MVAR STATCOM at Coopers Mills	Nov-18	4
1341, 1645	Install a 115 kV 36.7 MVAR capacitor bank at Hartwell	May-17	4
1646	Install a 345 kV 160 MVAR shunt reactor at K Street	Dec-19	4
1647	Install a 115 kV breaker in series with the 5 breaker at Framingham	Mar-17	4
1554	Install a 115 kV breaker in series with the 29 breaker at K Street	Apr-17	4

SEMA/RI Reliability Projects

Status as of 9/27/2021

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

RSP Project List 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	Oct-20	4
1742	Conduct remote terminal station work at the Wampanoag and Pawtucket substations for the new Grand Army GIS switching station	Oct-20	4
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	Oct-20	4
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 9/27/2021

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1718	Add 115 kV circuit breaker at Robinson Ave substation and re-terminate the Q10 line	Mar-22	3
1719	Install 45.0 MVAR capacitor bank at Berry Street substation	Cancelled*	N/A
1720	Separate the N12/M13 DCT and reconductor the N12 and M13 between Somerset and Bell Rock substations	May-25	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-23	3
1722	Extend the Line 114 from the Dartmouth town line (Eversource-National Grid border) to Bell Rock substation	Dec-23	2
1723	Reconductor L14 and M13 lines from Bell Rock substation to Bates Tap	Cancelled*	N/A

*Cancelled per ISO-NE PAC presentation on August 27, 2020

SEMA/RI Reliability Projects, cont.

Status as of 9/27/2021

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

RSP Project List 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-23	1
1726	Separate the 135/122 DCT from West Barnstable to Barnstable substations	Dec-21	3
1727	Retire the Barnstable SPS	Dec-21	3
1728	Build a new 115 kV line from Carver to Kingston substations and add a new Carver terminal	Dec-22	1
1729	Install a new bay position at Kingston substation to accommodate new 115 kV line	Dec-22	1
1730	Extend the 114 line from the Eversource/National Grid border to the Industrial Park Tap	Dec-23	1

SEMA/RI Reliability Projects, cont.

Status as of 9/27/2021

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1731	Install 35.3 MVAR capacitors at High Hill and Wing Lane substations	Dec-21	3
1732	Loop the 201-502 line into the Medway substation to form the 201-502N and 201-502S lines	Jan-23	3
1733	Separate the 325/344 DCT lines from West Medway to West Walpole substations	Cancelled**	N/A
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	Aug-20	4

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

** Cancelled per ISO-NE PAC presentation on August 27, 2020

SEMA/RI Reliability Projects, cont.

Status as of 9/27/2021

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

RSP Project List 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	Jun-22	2
1724	Replace the Kent County 345/115 kV transformer	Mar-22	2
1789	West Medway 345 kV circuit breaker upgrades	Apr-21	4
1790	Medway 115 kV circuit breaker replacements	Nov-20	4

Eastern CT Reliability Projects

Status as of 9/27/2021

Project Benefit: Addresses system needs in the Eastern Connecticut area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1815	Reconductor the L190-4 and L190-5 line sections	Dec-24	2
1850	Install a second 345/115 kV autotransformer (4X) and one 345 kV breaker at Card substation	Mar-23	2
1851	Upgrade Card 115 kV to BPS standards	Mar-23	2
1852	Install one 115 kV circuit breaker in series with Card substation 4T	Mar-23	2
1853	Convert Gales Ferry substation from 69 kV to 115 kV	Dec-23	1
1854	Rebuild the 100 Line from Montville to Gales Ferry to allow operation at 115 kV	Dec-22	1

Eastern CT Reliability Projects, cont.

Status as of 9/27/2021

Project Benefit: Addresses system needs in the Eastern Connecticut area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1855	Re-terminate the 100 Line at Montville station and associated work. Energize the 100 Line at 115 kV	Dec-23	1
1856	Rebuild 400-1 Line section to allow operation at 115 kV (Tunnel to Ledyard Jct.)	Dec-22	1
1857	Add one 115 kV circuit breaker and re-terminate the 400-1 line section into Tunnel substation. Energize 400 Line at 115 kV	Dec-23	1
1858	Rebuild 400-2 Line section to allow operation at 115 kV (Ledyard Jct. to Border Bus with CMEEC)	Dec-21	3
1859	Rebuild the 400-3 Line Section to allow operation at 115 kV (Gales Ferry to Ledyard Jct.)	Dec-22	1
1860	Install a 25.2 MVAR 115 kV capacitor and one capacitor breaker at Killingly	Mar-22	2

Eastern CT Reliability Projects, cont.

Status as of 9/27/2021

Project Benefit: Addresses system needs in the Eastern Connecticut area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1861	Install one 345 kV series breaker with the Montville 1T	June-22	2
1862	Install a 50 MVAR synchronous condenser with two 115 kV breakers at Shunock	Dec-24	1
1863	Install a 1% series reactor with bypass switch at Mystic, CT on the 1465 Line	Dec-22	1
1864	Convert the 400-2 Line Section to 115 kV (Border Bus to Buddington), convert Buddington to 115 kV	Dec-23	1

Boston Area Optimized Solution Projects

Status as of 9/27/2021

Project Benefit: Addresses system needs in the Boston area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1874	Install two 11.9 ohm series reactors at North Cambridge Station on Lines 346 and 365	Jun-23	3
1875	Install a direct transfer trip (DTT) scheme between Ward Hill and West Amesbury Substations for Line 394	Jan-23	2
1876	Install one +/- 167 MVAR STATCOM at Tewksbury 345 kV Substation	Oct-23	2

New Hampshire Solution Projects

Status as of 9/27/2021

Project Benefit: Addresses system needs in the New Hampshire area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1878	Install a +50/-25 MVAR synchronous condenser at N. Keene 115 kV Substation with a 115 kV breaker	Aug-23	2
1879	Install a +50/-25 MVAR synchronous condenser at Huckins Hill 115 kV Substation with a 115 kV breaker	Aug-23	2
1880	Install a +100/-50 MVAR synchronous condenser at Amherst 345 kV Substation with two 345 kV breakers	Dec-23	1
1881	Install two 50 MVAR capacitors on Line 363 near Seabrook Station with three 345 kV breakers	Nov-23	1

Upper Maine Solution Projects

Status as of 9/27/2021

Project Benefit: Addresses system needs in the Upper Maine area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1882	Rebuild 21.7 miles of the existing 115 kV line Section 80 Highland – Coopers Mills 115 kV line	Dec-27	1
1883	Convert the Highland 115 kV substation to an eight breaker, breaker-and-a-half configuration with a bus connected 115/34.5 kV transformer	Dec-27	1
1884	Install a 15 MVAR capacitor at Belfast 115 kV substation	Dec-27	1
1885	Install a +50/-25 MVAR synchronous condenser at Highland 115 kV substation	Dec-27	1
1886	Install +50/-25 MVAR synchronous condenser at Boggy Brook 115 kV substation, and install a new 115 kV breaker to separate Line 67 from the proposed solution elements	Dec-25	1

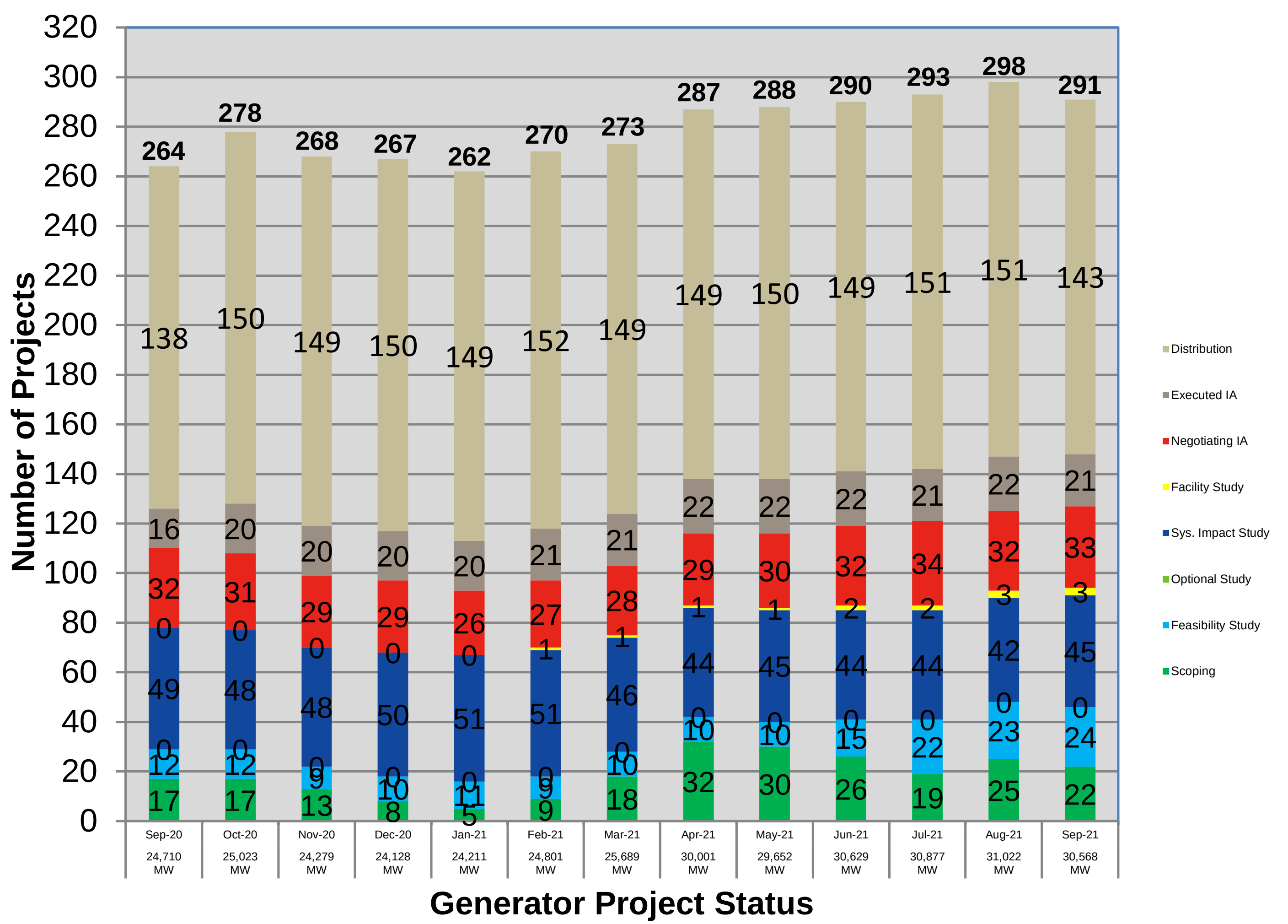
Upper Maine Solution Projects, cont.

Status as of 9/27/2021

Project Benefit: Addresses system needs in the Upper Maine area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1887	Install 25 MVAR reactor at Boggy Brook 115 kV substation	Dec-25	1
1888	Install 10 MVAR reactor at Keene Road 115 kV substation	Dec-23	1
1889	Install three remotely monitored and controlled switches to split the existing Orrington reactors between the two Orrington 345/115 kV autotransformers	Dec-23	1

Status of Tariff Studies



Note: September 2021 is based on partial data.

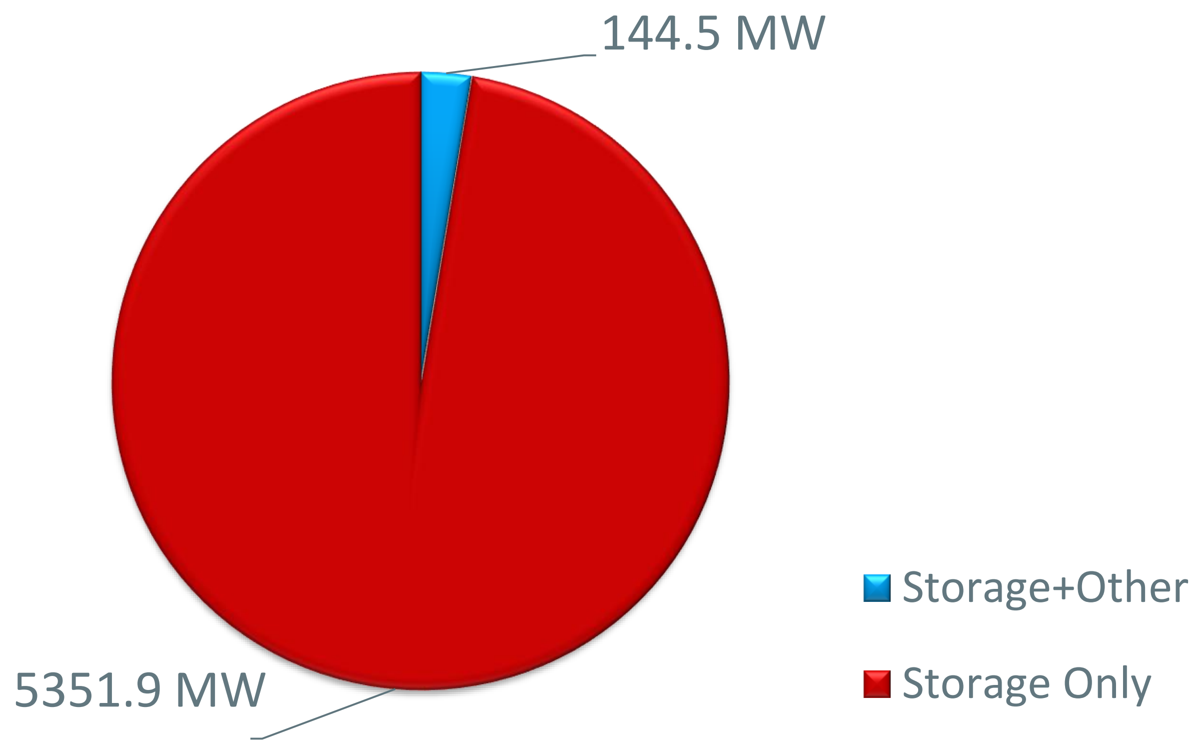
As of September 2021: 3 ETUs in Scoping, 0 in FS, 2 in SIS, 0 in OIS, 1 in FAC, 0 Negotiating IA, and 2 with Executed IA

Transmission Service Requests needing study: 1 in Scoping

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

What is in the Queue (as of September 28, 2021)

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



OPERABLE CAPACITY ANALYSIS

Fall 2021 Analysis

Fall 2021 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Oct. - 2021[2] CSO (MW)	Oct. - 2021[2] SCC (MW)
Operable Capacity MW [1]	29,714	32,069
Active Demand Capacity Resource (+) [5]	492	398
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,068	1,068
Non Commercial Capacity (+)	42	42
Non Gas-fired Planned Outage MW (-)	4,865	5,455
Gas Generator Outages MW (-)	4,236	4,850
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	19,415	20,473
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	15,749	15,749
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	18,054	18,054
Operable Capacity Margin	1,362	2,419

[1] Operable Capacity is based on data as of **September 28, 2021** 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 **September 28, 2021.**

[2] Load forecast that is based on the 2021 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **October 16, 2021.**

[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.

Fall 2021 Operable Capacity Analysis

90/10 Load Forecast	Oct. - 2021[2] CSO (MW)	Oct. - 2021[2] SCC (MW)
Operable Capacity MW [1]	29,714	32,069
Active Demand Capacity Resource (+) [5]	492	398
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,068	1,068
Non Commercial Capacity (+)	42	42
Non Gas-fired Planned Outage MW (-)	4,865	5,455
Gas Generator Outages MW (-)	4,236	4,850
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	19,415	20,473
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	16,279	16,279
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	18,584	18,584
Operable Capacity Margin	832	1,889

[1]Operable Capacity is based on data as of **September 28, 2021** 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 **September 28, 2021.**

[2] Load forecast that is based on the 2021 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **October 16, 2021.**

[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.

Fall 2021 Operable Capacity Analysis
50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

September 28, 2021 - 50-50 FORECAST using CSO MW

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.

Report created: 9/28/2021

Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 50-50PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 50-50PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
10/16/2021	**29714**	**492**	**1068**	**42**	**4865**	**4236**	**2800**	**0**	**19415**	**15749**	**2305**	**18054**	**1362**	**Y**	**Fall 2021**
10/23/2021	29714	492	1011	42	4601	2779	2800	0	21079	16113	2305	18418	2662	N	Fall 2021
10/30/2021	29750	540	1135	50	5091	1349	3600	0	21435	16320	2305	18625	2810	N	Fall 2021
11/6/2021	29750	540	1135	50	2480	1322	3600	0	24073	16435	2305	18740	5334	N	Fall 2021
11/13/2021	29750	540	1135	50	1723	1434	3600	0	24718	16780	2305	19085	5633	N	Fall 2021
11/20/2021	29750	540	1135	50	1088	8	3600	1362	25417	17517	2305	19822	5596	N	Fall 2021

Column Definitions

1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).
These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.
4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.
5. CSO Non Gas-Only Generator Planned Outages MW: All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.
6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)
10. Peak Load Forecast MW: Provided in the annual 2021 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

Fall 2021 Operable Capacity Analysis
90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

September 28, 2021 - 90/10 FORECAST using CSO MW

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 December, January, February, March and April.

Report created: 9/28/2021

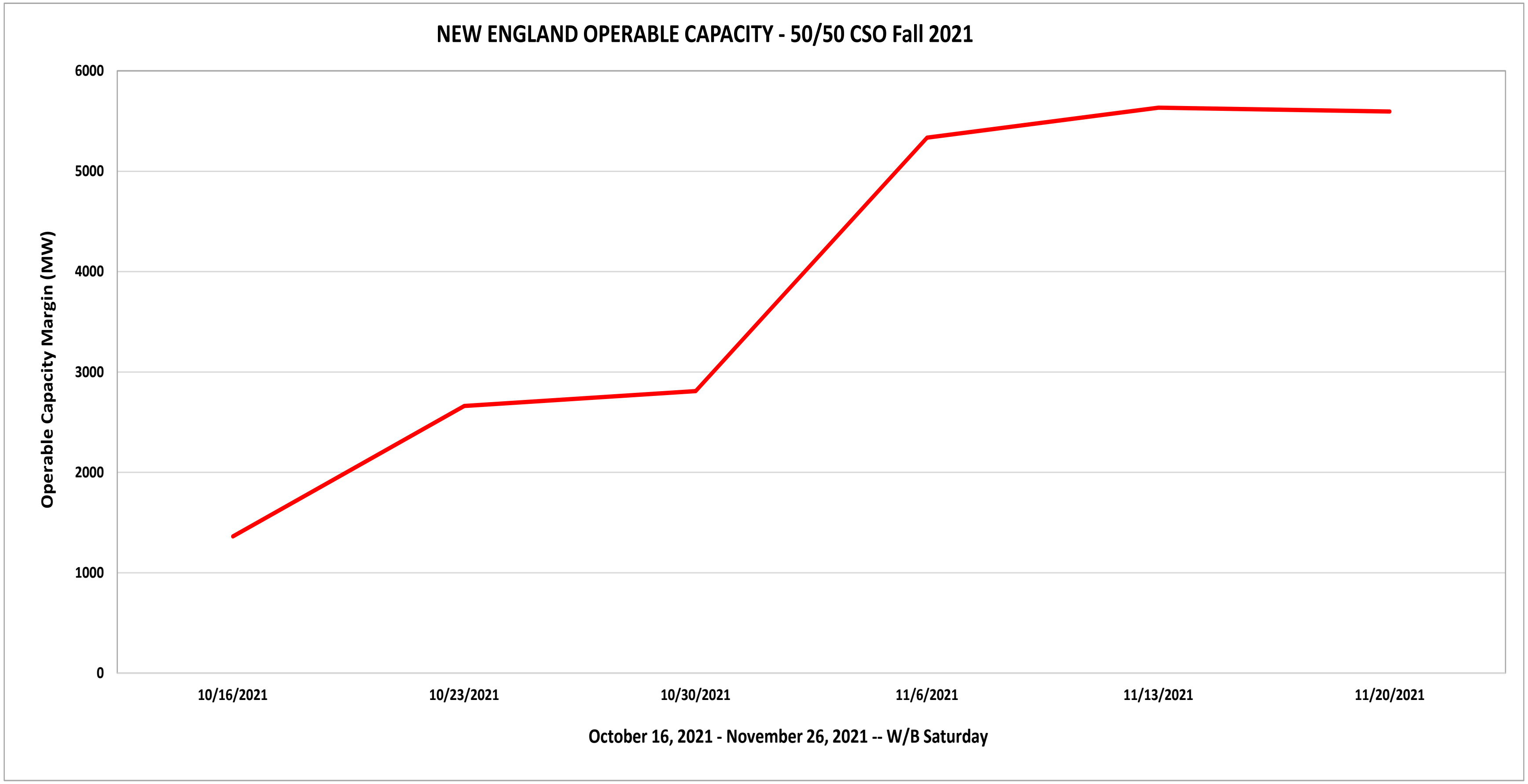
Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 90-10PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 90-10PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
10/16/2021	**29714**	**492**	**1068**	**42**	**4865**	**4236**	**2800**	**0**	**19415**	**16279**	**2305**	**18584**	**832**	**Y**	**Fall 2021**
10/23/2021	29714	492	1011	42	4601	2779	2800	0	21079	16654	2305	18959	2121	N	Fall 2021
10/30/2021	29750	540	1135	50	5091	1349	3600	0	21435	16866	2305	19171	2264	N	Fall 2021
11/6/2021	29750	540	1135	50	2480	1322	3600	0	24073	16985	2305	19290	4784	N	Fall 2021
11/13/2021	29750	540	1135	50	1723	1434	3600	101	24617	17339	2305	19644	4973	N	Fall 2021
11/20/2021	29750	540	1135	50	1088	8	3600	2297	24482	18098	2305	20403	4080	N	Fall 2021

Column Definitions

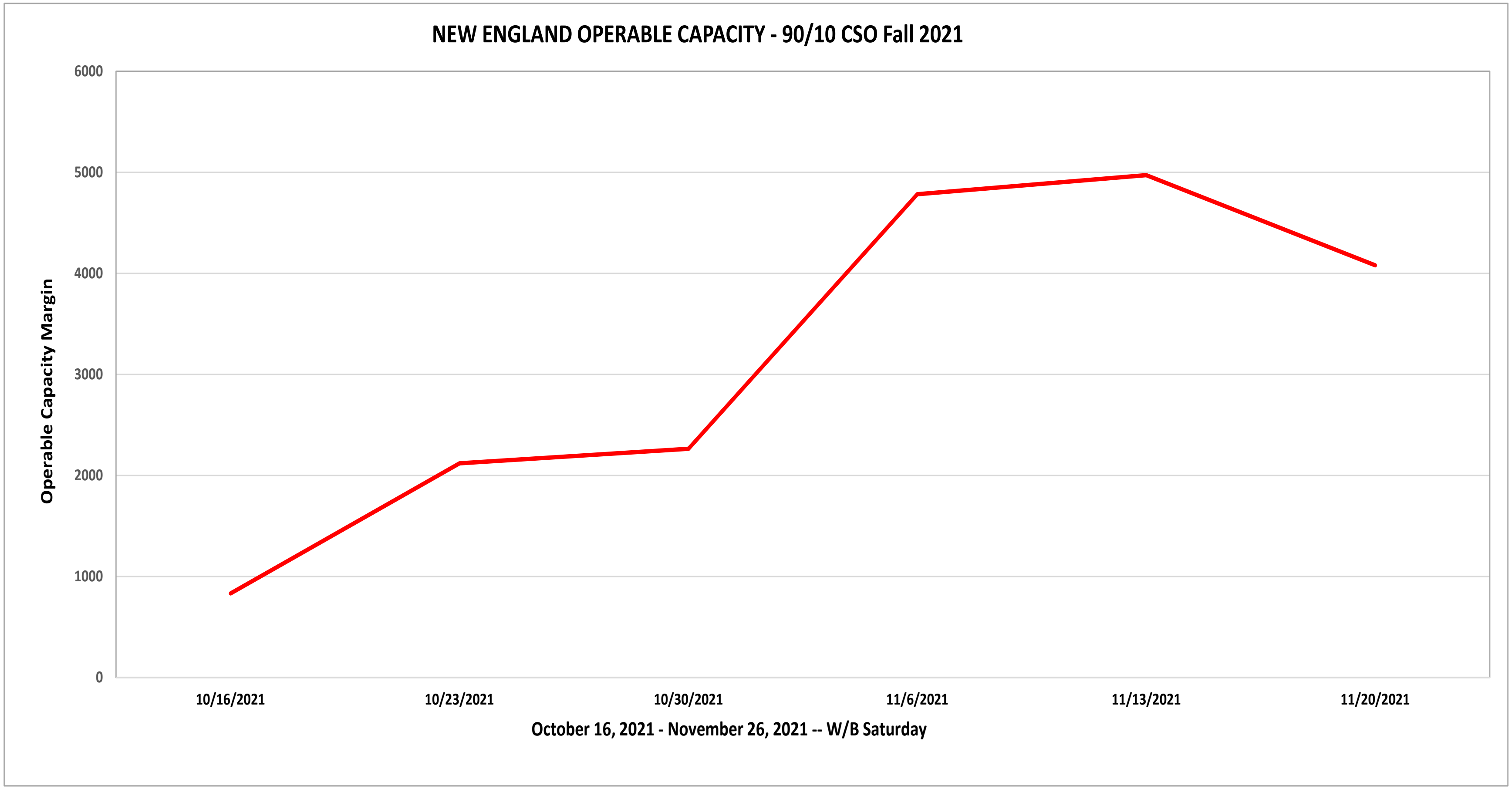
1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).
These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.
4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.
5. CSO Non Gas-Only Generator Planned Outages MW: All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.
6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)
10. Peak Load Forecast MW: Provided in the annual 2021 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

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

Fall 2021 Operable Capacity Analysis
50/50 Forecast (Reference)



Fall 2021 Operable Capacity Analysis
90/10 Forecast



OPERABLE CAPACITY ANALYSIS

Preliminary Winter 2021/22 Analysis

Preliminary Winter 2021/22 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Jan. - 2022[2] CSO (MW)	Jan. - 2022[2] SCC (MW)
Operable Capacity MW [1]	29,774	32,069
Active Demand Capacity Resource (+) [5]	541	398
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,135	1,135
Non Commercial Capacity (+)	50	50
Non Gas-fired Planned Outage MW (-)	296	401
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	3,735	4,287
Net Capacity (NET OPCAP SUPPLY MW)	24,669	26,164
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	19,710	19,710
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,015	22,015
Operable Capacity Margin	2,654	4,149

[1] Operable Capacity is based on data as of **September 28, 2021** 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 **September 28, 2021.**

[2] Load forecast that is based on the 2021 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 8, 2022.**

[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 Winter 2021/22 Operable Capacity Analysis

90/10 Load Forecast	Jan. - 2022[2] CSO (MW)	Jan. - 2022[2] SCC (MW)
Operable Capacity MW [1]	29,774	32,069
Active Demand Capacity Resource (+) [5]	541	398
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,135	1,135
Non Commercial Capacity (+)	50	50
Non Gas-fired Planned Outage MW (-)	296	401
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	4,546	5,217
Net Capacity (NET OPCAP SUPPLY MW)	23,858	25,234
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,349	20,349
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,654	22,654
Operable Capacity Margin	1,204	2,580

[1]Operable Capacity is based on data as of **September 28, 2021** 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 **September 28, 2021.**

[2] Load forecast that is based on the 2021 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 8, 2022.**

[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 Winter 2021/22 Operable Capacity Analysis
50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

September 28, 2021 - 50-50 FORECAST using CSO MW

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.

Report created: 9/28/2021

Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 50-50PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 50-50PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
11/27/2021	29750	540	1135	50	1123	8	3600	1950	24794	18237	2305	20542	4253	N	Winter 2021/2022
12/4/2021	29774	541	1135	50	387	272	3200	2110	25531	18611	2305	20916	4615	N	Winter 2021/2022
12/11/2021	29774	541	1135	50	358	270	3200	2311	25361	18900	2305	21205	4156	N	Winter 2021/2022
12/18/2021	29774	541	1135	50	303	0	3200	2794	25203	18911	2305	21216	3987	N	Winter 2021/2022
12/25/2021	29774	541	1135	50	303	0	3200	3141	24856	18973	2305	21278	3578	N	Winter 2021/2022
1/1/2022	29774	541	1135	50	307	0	2800	3740	24653	19246	2305	21551	3102	N	Winter 2021/2022
1/8/2022	**29774**	**541**	**1135**	**50**	**296**	**0**	**2800**	**3735**	**24669**	**19710**	**2305**	**22015**	**2654**	**Y**	**Winter 2021/2022**
1/15/2022	29774	541	1135	50	296	0	2800	3590	24814	19710	2305	22015	2799	N	Winter 2021/2022
1/22/2022	29774	541	1135	50	296	0	2800	3141	25263	19710	2305	22015	3248	N	Winter 2021/2022
1/29/2022	29774	541	1135	50	296	0	3100	2842	25262	19488	2305	21793	3469	N	Winter 2021/2022
2/5/2022	29774	541	1135	50	296	0	3100	2543	25561	19222	2305	21527	4034	N	Winter 2021/2022
2/12/2022	29774	541	1135	50	289	0	3100	2244	25867	19193	2305	21498	4369	N	Winter 2021/2022
2/19/2022	29774	541	1135	50	291	18	3100	1777	26314	18931	2305	21236	5078	N	Winter 2021/2022
2/26/2022	29774	541	1135	50	346	18	3100	1478	26558	17944	2305	20249	6309	N	Winter 2021/2022
3/5/2022	29774	541	1135	50	350	270	2200	927	27753	17596	2305	19901	7852	N	Winter 2021/2022
3/12/2022	29774	541	1135	50	634	718	2200	0	27949	17400	2305	19705	8244	N	Winter 2021/2022
3/19/2022	29774	541	1135	50	1058	1120	2200	0	27122	17036	2305	19341	7781	N	Winter 2021/2022
3/26/2022	29750	540	1135	50	1698	757	2700	0	26320	16472	2305	18777	7544	N	Winter 2021/2022

Column Definitions

1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).

2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM). These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.

3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.

4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.

5. CSO Non Gas-Only Generator Planned Outages MW: All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.

6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.

7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.

8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.

9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)

10. Peak Load Forecast MW: Provided in the annual 2021 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).

11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.

12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)

13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)

14. Operable Capacity Season Label: Applicable season and year.

15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

Preliminary Winter 2021/22 Operable Capacity Analysis
90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

September 28, 2021 - 90/10 FORECAST using CSO MW

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 December, January, February, March and April.

Report created: 9/28/2021

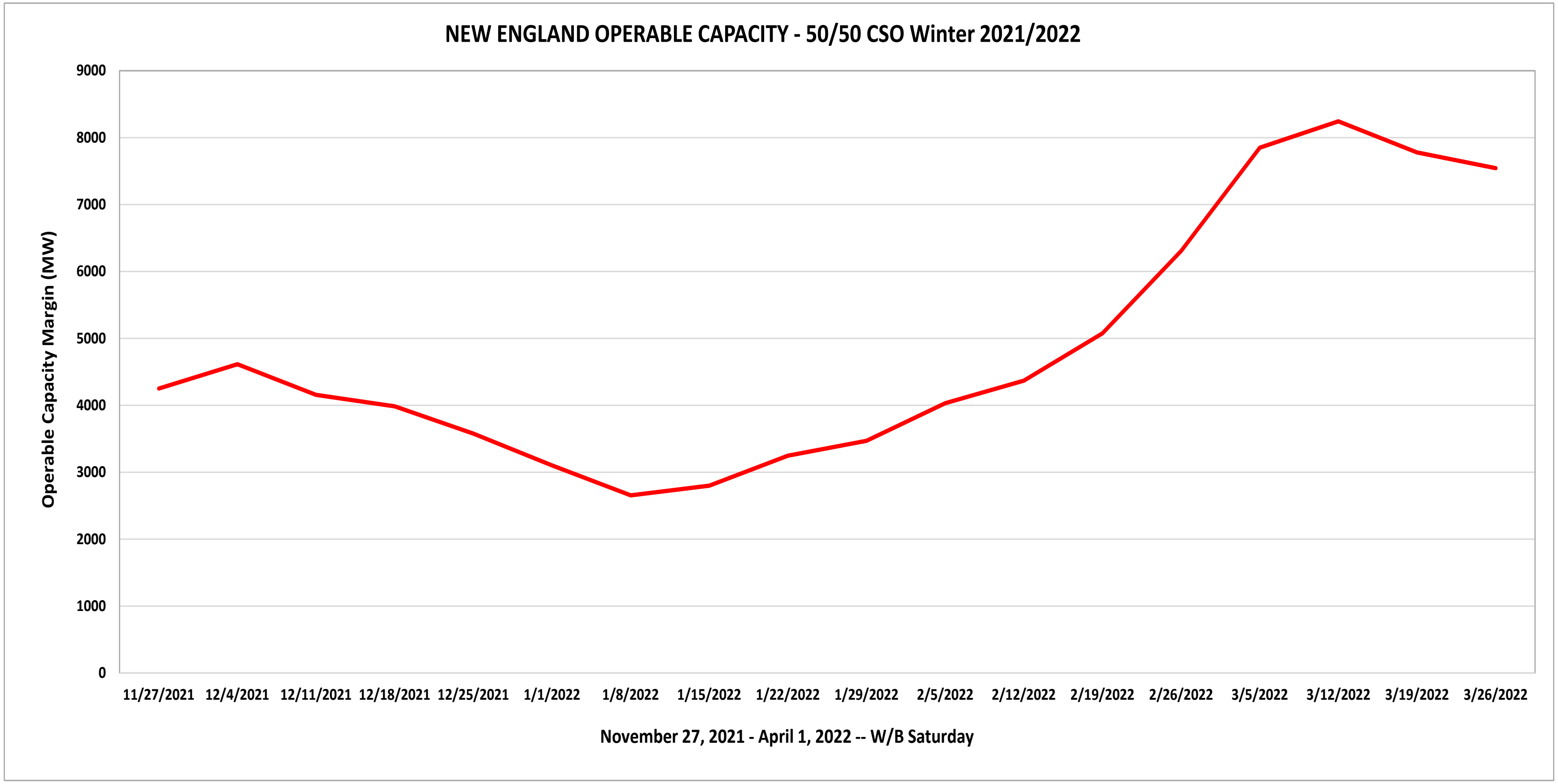
Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 90-10PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 90-10PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
11/27/2021	29750	540	1135	50	1123	8	3600	2864	23880	18838	2305	21143	2738	N	Winter 2021/2022
12/4/2021	29774	541	1135	50	387	272	3200	3098	24543	19218	2305	21523	3020	N	Winter 2021/2022
12/11/2021	29774	541	1135	50	358	270	3200	3298	24374	19515	2305	21820	2554	N	Winter 2021/2022
12/18/2021	29774	541	1135	50	303	0	3200	3913	24084	19527	2305	21832	2252	N	Winter 2021/2022
12/25/2021	29774	541	1135	50	303	0	3200	4287	23710	19591	2305	21896	1814	N	Winter 2021/2022
1/1/2022	29774	541	1135	50	307	0	2800	4415	23978	19872	2305	22177	1801	N	Winter 2021/2022
1/8/2022	**29774**	**541**	**1135**	**50**	**296**	**0**	**2800**	**4546**	**23858**	**20349**	**2305**	**22654**	**1204**	**Y**	**Winter 2021/2022**
1/15/2022	29774	541	1135	50	296	0	2800	4338	24066	20349	2305	22654	1412	N	Winter 2021/2022
1/22/2022	29774	541	1135	50	296	0	2800	4039	24365	20349	2305	22654	1711	N	Winter 2021/2022
1/29/2022	29774	541	1135	50	296	0	3100	4039	24065	20121	2305	22426	1639	N	Winter 2021/2022
2/5/2022	29774	541	1135	50	296	0	3100	3590	24514	19847	2305	22152	2362	N	Winter 2021/2022
2/12/2022	29774	541	1135	50	289	0	3100	3291	24820	19817	2305	22122	2698	N	Winter 2021/2022
2/19/2022	29774	541	1135	50	291	18	3100	2675	25416	19547	2305	21852	3564	N	Winter 2021/2022
2/26/2022	29774	541	1135	50	346	18	3100	2226	25810	18533	2305	20838	4972	N	Winter 2021/2022
3/5/2022	29774	541	1135	50	350	270	2200	1824	26856	18174	2305	20479	6377	N	Winter 2021/2022
3/12/2022	29774	541	1135	50	634	718	2200	778	27170	17973	2305	20278	6892	N	Winter 2021/2022
3/19/2022	29774	541	1135	50	1058	1120	2200	0	27122	17598	2305	19903	7219	N	Winter 2021/2022
3/26/2022	29750	540	1135	50	1698	757	2700	0	26320	17017	2305	19322	6999	N	Winter 2021/2022

Column Definitions

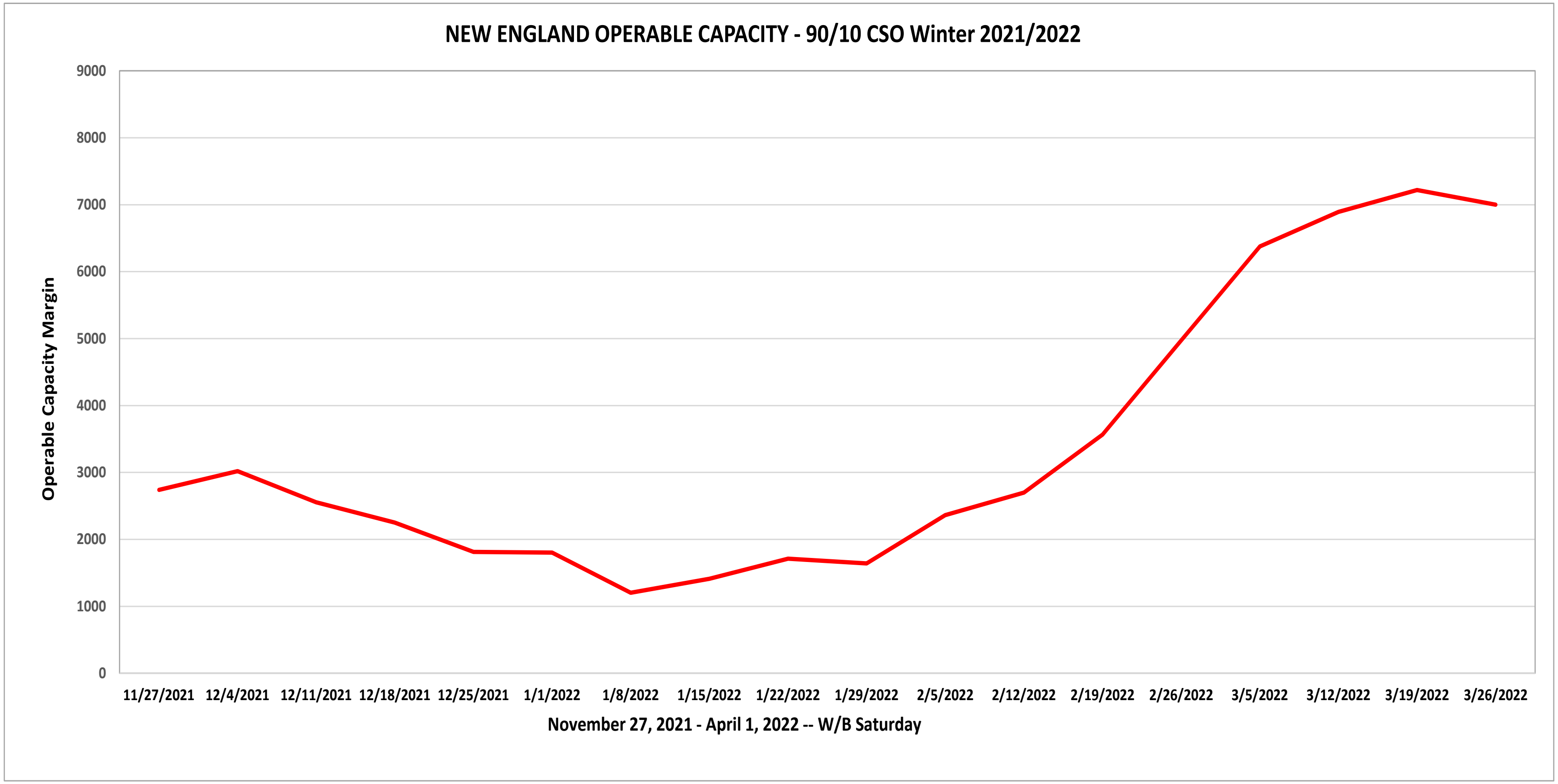
1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM). These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.
4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.
5. CSO Non Gas-Only Generator Planned Outages MW: All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.
6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)
10. Peak Load Forecast MW: Provided in the annual 2021 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

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

Preliminary Winter 2021/22 Operable Capacity Analysis
50/50 Forecast (Reference)



Preliminary Winter 2021/22 Operable Capacity Analysis
90/10 Forecast



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 resources <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 resources <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

SEPTEMBER 27, 2021

ISO New England's Draft 2022 Annual Work Plan

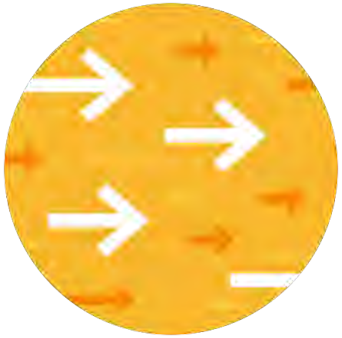
For Discussion at the October 7, 2021, NEPOOL Participants Committee Meeting

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

2022 Objectives and Highlights

Advancing a reliable clean-energy transition through innovation and collaboration



- **Anchor projects** require dedicated focus and a regional commitment to securing power system reliability while facilitating the integration of clean-energy and distributed resources
  - **Market Improvements for the Current and Future Grid**
    - **Resource Capacity Accreditation** to accurately reflect resource contributions to resource adequacy in the capacity market as the resource mix transforms
    - **Day-Ahead Ancillary Service Improvements** to create pricing incentives for specific energy and reserve capabilities needed for reliability as the resource mix and regional energy demand evolve
  - **Transmission Planning for the Future Grid**
    - **Extended-Term Transmission Planning** to support recurring assessments of a future system beyond the current ten-year transmission planning horizon by modifying the ISO Tariff
    - **2050 Transmission Study** to assess the amount, type, and high-level cost estimates of transmission infrastructure necessary to maintain reliability with prospective renewable and distributed energy expansions to meet states' energy policies
  - **Operational Impacts of Extreme Weather Events** to model and assess low-probability, high-impact weather risks under New England's changing power system
- **Notable initiatives underway** target innovation, advance efficiency, and help manage risks across markets, planning, operations, and software structures
- **Other potential projects** may emerge but not achievable for development in 2022

Project Timing and Effects of Shifting Priorities

The ISO strives to support the reliability and decarbonization goals of the region in a coordinated manner

- Project timing
  - Because the planning/study phases of a number of projects are scheduled to be completed in early 2022, follow-on work, such as additional studies or design work, would need to be discussed at that time; this work is broadly identified here but may be clarified in the Spring 2022 Annual Work Plan Update

- Shifting priorities
  - FERC actions (orders, notices of proposed rulemaking) and policy directives can shift regional priorities
  - Increased or expanded stakeholder requests, regional policy interests, and new issues will affect project schedules of planned efforts
  - Upfront agreement on priorities helps keep the region's anchor projects on track

ANCHOR PROJECTS

Market Improvements for the Current and Future Grid

Maintaining Resource Adequacy: Resource Capacity Accreditation (RCA) in the Forward Capacity Market (FCM)

Reforming the way resources are qualified in the FCM to support a reliable, clean-energy transition

- This major effort seeks to identify and implement methodologies that will more appropriately accredit resource contributions to resource adequacy as the resource mix transforms
  - It is critical to reliability and market efficiency that the methodologies are updated to reflect resources' capabilities and how those capabilities contribute to resource adequacy
- The ISO has begun assessing and discussing methodologies with stakeholders, including how Effective Load Carrying Capability (ELCC) techniques could be used in quantifying resource capacity contributions to regional resource adequacy
- After its assessment and in consultation with stakeholders during the project phase, the ISO will finalize its filing and implementation timeline
  - Currently contemplating a FERC filing by the end of 2022, targeting Forward Capacity Auction (FCA) 18, and a second filing by the end of 2023, targeting FCA 19

Day-Ahead Ancillary Services Improvements

Procuring and transparently pricing the ancillary service capabilities needed for a reliable next-day operating plan with an evolving generation fleet

- As the power system transforms, new and updated ancillary products and services are needed to procure and price:
  1) the "gap" between day-ahead physical energy supply awards and the ISO's forecast real-time load, and
  2) day-ahead generation contingency response capabilities
- In 2022, the ISO will revisit efforts to co-optimize reserves in the day-ahead energy markets
  - This includes developing both the product design (focused on Energy Imbalance Reserve and Generation Contingency Reserve) and the mitigation design, as well as conforming market changes, including elimination of the Forward Reserve Market
- The ISO anticipates it will take until mid-late 2023 to complete (e.g., design, impact assessment, stakeholder process, and regulatory process)

ANCHOR PROJECTS

Operations and Planning Improvements for the Future Grid

Transmission Planning for the Future Grid

Providing transmission planning beyond a 10-year horizon that assesses a reliable, clean-energy future grid (initiated in response to the New England States' Energy Vision)

- **Extended-Term Transmission Planning**: The ISO is proposing changes to Attachment K of the Open Access Transmission Tariff to create a process that will allow the New England States to request, on a recurring basis, the ISO to perform extended-term planning analyses on the system beyond the current 10-year planning horizon
  - Beginning in 2022, the ISO also expects to discuss with stakeholders a second phase of Tariff changes to allow a process for states to consider potential options in addressing longer-term issues and cost allocation
  - Ongoing processes at FERC may further inform this effort
- **2050 Transmission Study**: The ISO is conducting a high-level transmission study for the years 2035, 2040, and 2050, that informs the region of the amount, type, and high-level cost estimates of transmission infrastructure that would be needed to cost-effectively incorporate clean-energy and distributed-energy resources and to meet state energy policy requirements and goals, including economy-wide decarbonization
  - The study looks well beyond the ISO's 10-year horizon for transmission planning to meet reliability needs so states can prepare for their future outlook
  - It is not a plan to build specific projects
  - The ISO anticipates sharing the scope, assumptions, and inputs requested by the states at the Planning Advisory Committee (PAC) in fall 2021

Modeling and Assessing Operational Impacts of Extreme Weather Events

Considering how to study New England's reliability risks from severe weather events

- The 2021 events in Texas have caused the ISO to further evaluate whether our region is adequately assessing and preparing for low-probability, high-impact reliability risks (tail risks)
- The ISO is initiating the project with discussion at the October 7, 2021, Participants Committee meeting; in Q1 2022 extending into 2023, the ISO and stakeholders will discuss approaches to modeling tail risks related to extreme weather events
- This process will:
  - Initially focus on understanding the modeling approaches to quantify such risks
  - Subsequently focus on understanding if and how the region should protect against the risks
- The ISO will work with Electric Power Research Institute on this project

NOTABLE INITIATIVES UNDERWAY

Major Initiatives Already Identified for 2022

New England's Future Grid Initiative

Assessing the future of the regional power system in light of state energy and environmental laws

- **Future Grid Reliability Study (FGRS) Phase 1:** For its 2021 Economic Study, the ISO is conducting a series of engineering and economic analyses that use stakeholder-defined scenarios to identify grid reliability challenges that could occur in the year 2040 in light of state energy policies; the ISO will issue a report in March 2022
- **Pathways to the Future Grid**: The ISO is evaluating potential market frameworks for facilitating the evolution of New England's power grid that reflects state energy policies; the ISO will issue a report on the following three studies in April 2022
  - **Study 1**: Evaluate a forward clean-energy market
  - **Study 2:** Evaluate net carbon pricing
  - **Study 3**: Evaluate a hybrid option that incorporates elements of the above two frameworks, as well as unique design components

New England's Future Grid Initiative, cont'd

Next steps on both initiatives will be discussed after study results are published

- **FGRS Phase 2**: Identify products or services that may need to be obtained via the ISO-administered markets to address gaps to reliably operating the future power system identified in Phase 1 (may address balancing services/resource issues)
  – Use of a consultant to assess system security and revenue sufficiency in a gap analysis; results of and issues resolved through Phase 1 and other future-grid-related studies will be critical inputs to and create efficiencies in how the Phase 2 analyses may be shaped
- **Pathways to the Future Grid**: Consideration of a preferred pathway and next steps

Capacity Markets without a Minimum Offer Price Rule (MOPR)

Developing a proposal to remove this component for FCA 17 while seeking to preserve the FCM's ability to attract new entry

- The MOPR requires minimum offer prices for new resources in the Forward Capacity Market
- Significant concerns have been raised at both the regional and federal level that the MOPR precludes resources sponsored by the states from clearing in the FCM
  - The FERC has identified this matter as its priority
- The ISO intends to develop a proposal with input from stakeholders to address the dual objectives of allowing sponsored resources to clear and maintaining competitive capacity pricing that can attract merchant entry when needed to maintain resource adequacy
- Following a robust stakeholder process in 2021 and early 2022, the ISO will file a proposal for FCA 17 in February 2022

FERC Order No. 2222 Compliance

Allowing participation of DER aggregations in wholesale markets

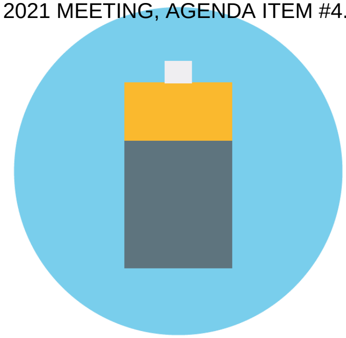
- FERC issued Order No. 2222 on September 17, 2020, which requires ISOs/RTOs to allow distributed energy resources (DERs) to provide all wholesale services that they are technically capable of providing through an aggregation of resources
- The ISO is dedicating resources to create a responsive market design, develop the compliance proposal through an extensive and comprehensive stakeholder process, and implement changes in ISO systems
- The compliance filing of proposed tariff revisions is due February 2, 2022; regulatory processes to follow for an unknown duration
  - Work during the remainder of 2022 (conforming changes/implementation) will depend on the progression of the regulatory process

Solar DNE Design

Enabling solar resources to be dispatched in the Real-Time Energy Market under the Do-Not-Exceed (DNE) model

- The quantity of front-of-meter solar generator assets in the New England region is expected to continue growing
- In 2022, the ISO will begin developing the rules, processes, forecasts, and tools necessary to enable these resources to take electronic dispatch instructions using the DNE model (as presently used with wind resources)
- Integrating these resources into the DNE dispatch process will help maximize the use of low-cost renewable energy, improve congestion management in constrained areas, and set appropriate price signals in the energy market
- The ISO expects to file changes with FERC in 2022 and implement the Solar DNE dispatch in Q3 2023

Additional Transmission Planning Enhancements for the Evolving Grid



Updated assumptions used in transmission planning studies will reflect future-grid trends and Tariff changes will allow storage to be considered as a transmission asset

- **Transmission Planning for the Clean-Energy Transition (CET):** The ISO, through the PAC process, has pilot tested a variety of transmission planning assumptions for 2030 (typical 10-year planning horizon); based on those results, the ISO will finalize and document new study conditions for load, solar generation, and wind generation to use going forward in its planning studies (e.g., Needs Assessments)
  - The ISO will continue further analyses into 2022 on renewable energy modeling and inter-area coordination of renewable energy integration—including detailed DER modeling, DER protection settings, and criteria for the acceptable level of DER tripping following transmission system events
- **Storage as a Transmission Solution**: Beginning in Q1 2022, the ISO will initiate discussions of proposed Tariff changes to consider storage as a transmission asset that meets transmission needs

Models and Tools to Support Future Grid Studies

Models, simulators, and other tools that are adaptive to evolving technologies and system conditions are needed to support future-grid studies

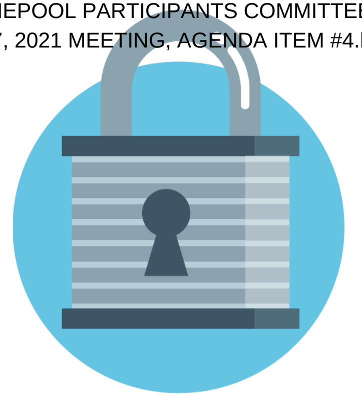
- **Inverter-Based Resource Integration and Modeling Assessment**: The ISO has begun a multi-year project (2021-2023) to assess and adopt advanced, innovative analysis techniques that capture the unique performance characteristics of inverter-based resources (e.g., solar and wind), critical to its studies beyond the 10-year horizon
  - By the end of 2021, the ISO will develop recommendations for the deployment of Electromagnetic Transient power system software and analytical methods that will enable efficient and reliable integration and modeling of rapidly-evolving inverter-based resources
  - In 2022, the ISO will begin to implement the recommendations to integrate hybrid-simulation processes and multi-core parallel capability into large-scale system studies, standardize the Electromagnetic Transient simulation workflow, and develop and deliver training to engineers
- **Integrated Market Simulator Development**: This is a multi-year project (2021-2023) to develop a new platform that will produce accurate, timely, long-term wholesale electricity market-simulation results through which the ISO can better and more cost-effectively quantify the potential outcomes of future market design changes, or potential changes in system supply and demand conditions, and aid in the ISO's research and development projects and cost impact studies
  - The ISO will complete the day-ahead portion of the market simulator in 2021 and will develop sub-hourly simulation and network analysis capability throughout 2022 and into 2023

nGEM Day-Ahead Market Clearing Engine Implementation

This is one project within the broader nGEM Program

- GE Solutions is modernizing its market application suite in a program called Next Generation Markets (nGEM), co-funded by GE, ISO-NE, MISO, PJM
  - The ISO's Market Management System (MMS) is based on the GE suite
  - This effort spans 2020-2027 and is broken into four phases
  - The ISO plans to update stakeholders on its nGEM program coincident with its Annual Work Plan presentation
- As part of this nGEM Phase 1 program, GE is developing a new market clearing engine (MCE) and implementation of the day-ahead version of this MCE will be a major focus in 2021 and 2022
  - In this timeframe, the ISO will be working on the complex processes for customizing and implementing the nGEM DA MCE software and infrastructure into the ISO's unique MMS
  - The DA MCE replaces the legacy MCE, and benefits include improved performance, flexibility, functionality, and scalability
  - The DA MCE is expected to be in-service Q1 2023

Enhance Cyber Security Tools



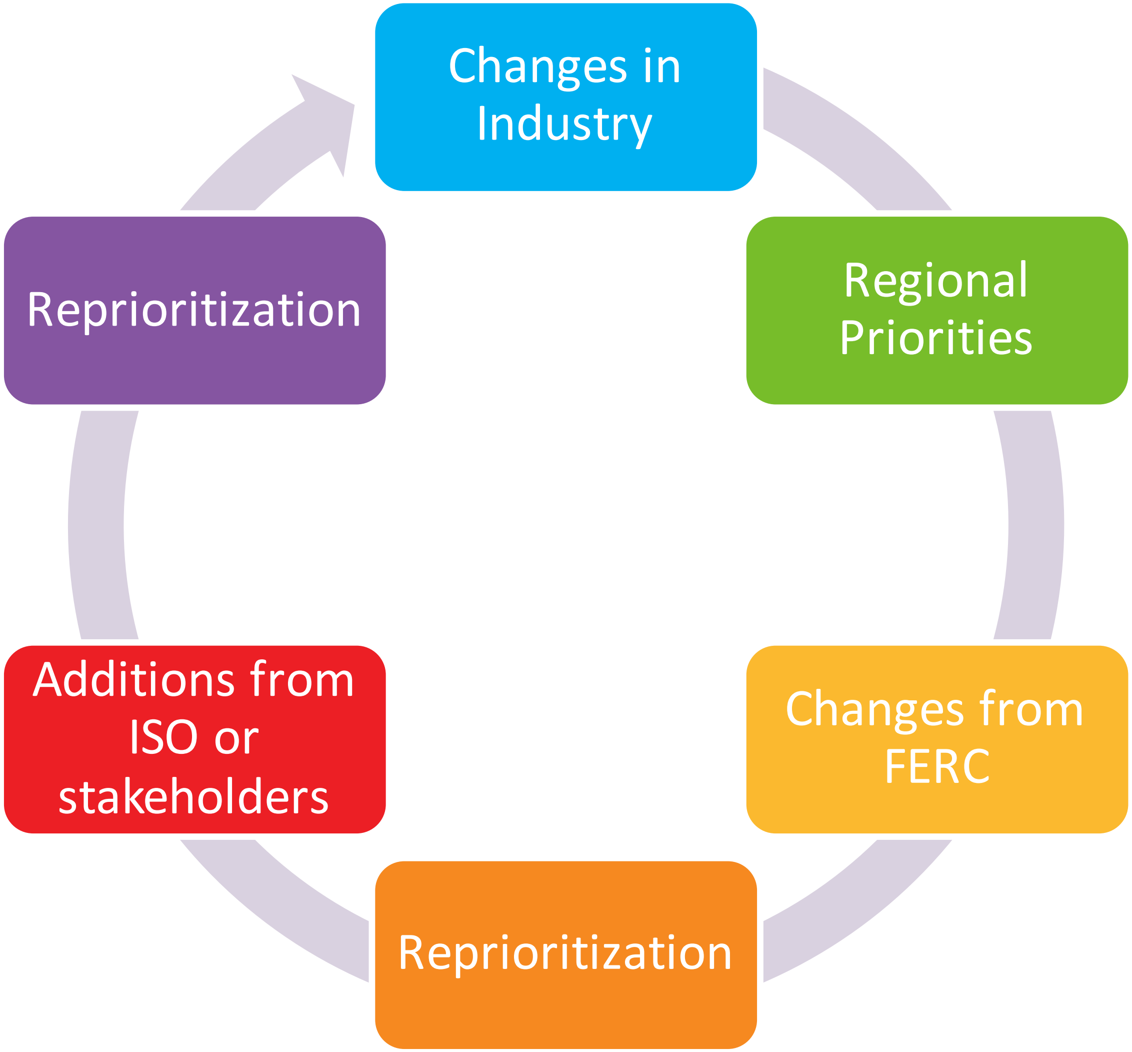
Upgrading monitoring, detection, and recovery tools to adapt to increasingly sophisticated threats and new attack vectors given ISO's heavy reliance on information technology

- **Identity & Access Management (IAM)** replaces the ISO's access rights application that records approval of users to thousands of ISO assets (e.g., applications, badged physical access, etc.)
  - IAM is the foundation of the ISO's cyber-security program: improves the functionality and security associated with logical and physical access management, and maintains compliance of these functions with NERC Critical Infrastructure Protection standards
  - Final phase to be completed by end of 2022
- **Security Information and Event Management (SIEM)** collects and correlates logs for monitoring and alerting on security events from hundreds of servers, network devices, and the applications running on them
  - ISO will implement new hardware by end of 2021 and software and related process changes by July 2022
- The **Cyber Security Improvements** project will refresh the hardware and software for the systems that support the collection of network traffic data that feeds the Network Intrusion Detection system and the Security Information and Event Management analysis system
  - The targeted completion date for this project is December 2022

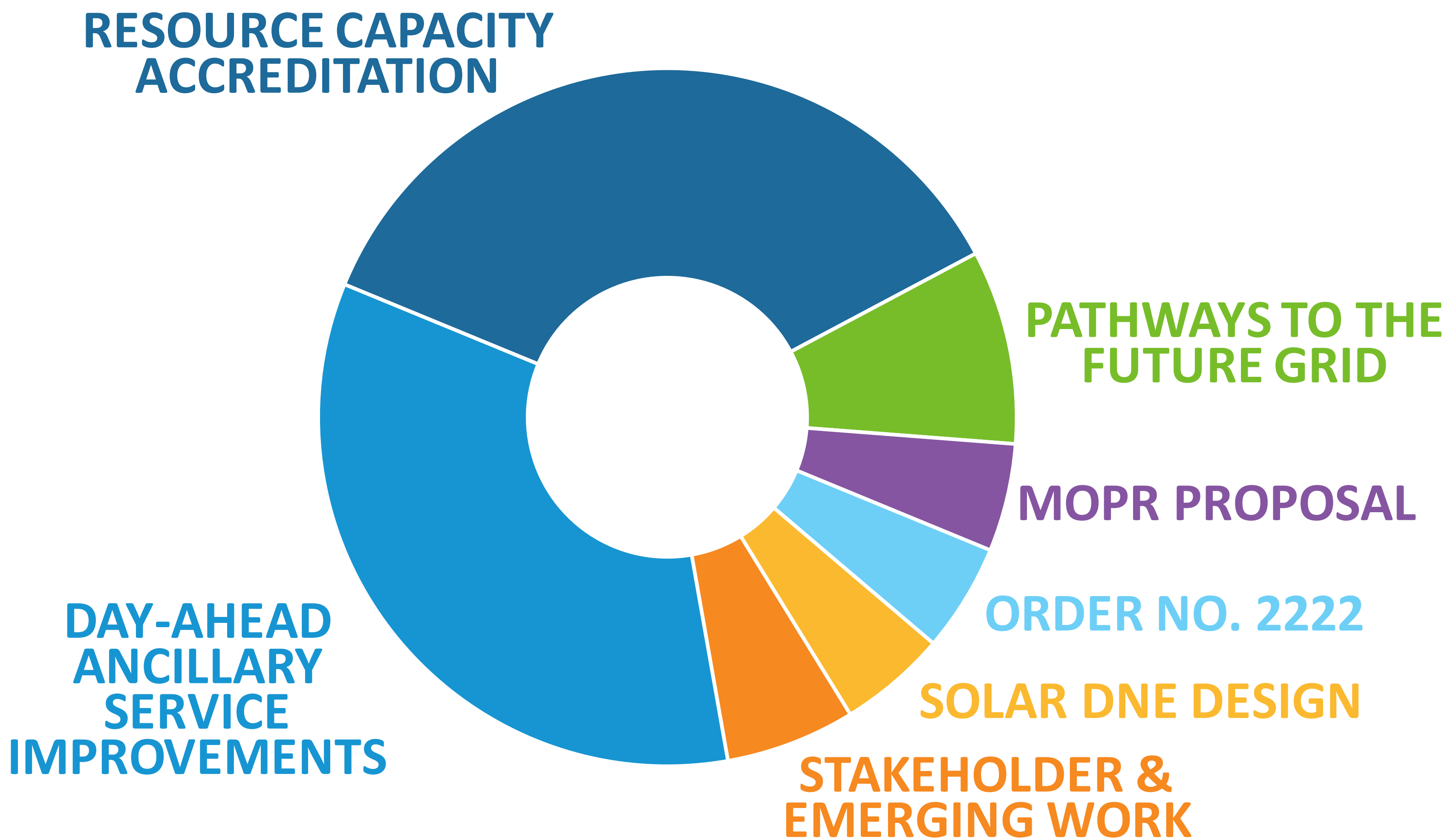
WORK PLAN PRIORITIZATION

Prioritization Process

- The ISO adjusts its priorities as needed to best maintain reliable operations, robustly plan for a changing grid, and ensure competitive wholesale markets
- Planned projects are impacted as scopes shift or new projects emerge



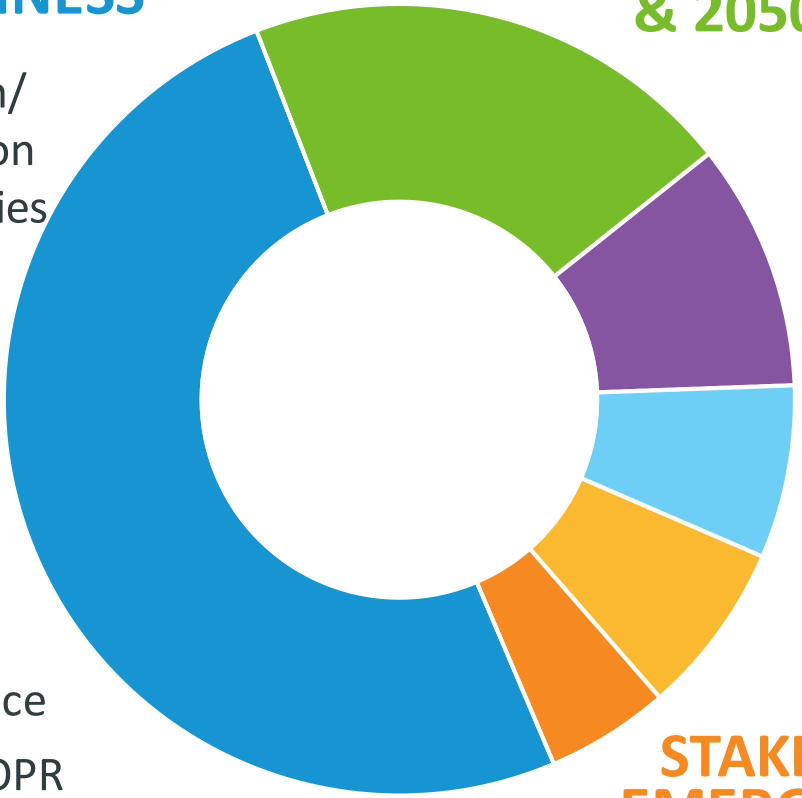
Markets-Related Priorities Include:



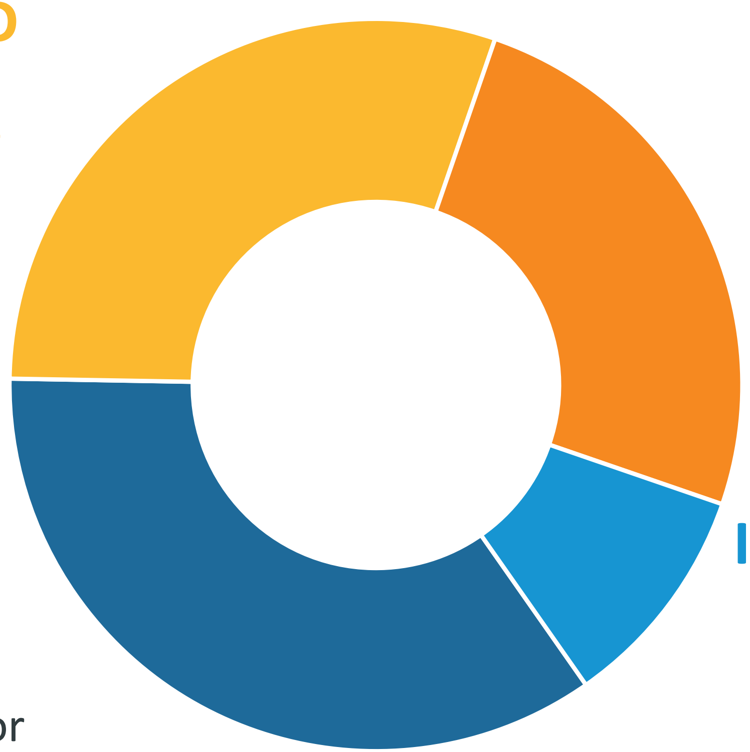
Planning/Operations Priorities Include:

CONTINUING BUSINESS

- Increased Generation/ Distributed Generation Interconnection studies due to increasing number of interconnection requests
- Administer FCA #16 and FCM-related modeling
- NERC/FERC Compliance
  - FERC ANOPR/NOPR
- 2022 Economic Study



Capital Project Priorities Include:



APPLICATION AND DATABASE ENHANCEMENTS

- FCTS
- IMM Data Analysis
- Integrated Market Simulator
- TranSMART
- FCM Accelerated Billing
- Issue Resolution
- Linear State Estimator
- Enterprise Application Integration
- TTC Calculator

CYBERSECURITY

- IAM
- SIEM
- Critical Infrastructure Protection Electronic Security Perimeter

IT INFRASTRUCTURE ENHANCEMENTS

- LMP Monitor
- Amazon Web Services Cloud Foundation
- Website Migration to Cloud

nGEM DAY-AHEAD MARKET CLEARING ENGINE IMPLEMENTATION

Markets Related

- Resource Capacity Accreditation
- Day-Ahead Ancillary Services Improvements
- Solar DNE Design
- Pathways to the Future Grid
- MOPR Proposal
- Order 2222 Compliance

Operations/ Planning

- Extended-Term Transmission Planning
- 2050 Transmission Study
- Extreme Weather Modeling
- FGRS Phase 1 (2021 Economic Study)
- Transmission Planning for the Clean Energy Transition
- Storage as Transmission Solution
- Continuing Business

Capital Project Priorities

- nGEM Day-Ahead Market Clearing Engine Implementation
- Cyber-Security Projects
- Application and Database Enhancements
- IT Infrastructure Enhancements

OCTOBER 7 | BOSTON, MA

Operational Impact of Extreme Weather Events

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Operational Impact of Extreme Weather Events – Introduction

- Recent experiences in Texas and California with extreme weather events have emphasized the importance of a comprehensive energy/resource adequacy assessment that covers a wide range of operating conditions
- The objective of this project is to conduct a probabilistic energy security study for the New England region in the operational time frame under extreme weather events

Operational Impact of Extreme Weather Events – Introduction

- The ISO will work with EPRI on this project
- The ISO effort will leverage the ongoing “Resource Adequacy for a Decarbonized Future” project by EPRI
- There are three major steps to this effort
  - Step 1: Extreme Weather Modeling (performed by EPRI)
  - Step 2: Risk Model Development and Scenario Generation (performed by EPRI)
  - Step 3: Energy security/adequacy assessments (performed by the ISO)
- Each of these major steps will be discussed with stakeholders
- This project is expected to take 15-18 months and will continue through the end of 2022/early 2023

Scope of Work – Step 1: Extreme Weather Modeling

- The objective of this step is to identify extreme weather events of interest, summer and winter, using probabilistic modeling
- This analysis begins with the acquisition and interpretation of locationally-specific climate data, both historical and projections
  - EPRI has developed and is expanding a repository of historical and projection climate data that includes multiple models and sources
  - This data repository will be used to characterize and visualize trends, including uncertainty, in the mean and extremes for different climate variables of interest

Scope of Work – Step 1: Extreme Weather Modeling, continued

- EPRI will incorporate future changes in weather variables
  - Future changes will be based on calculated trends for the near-term (next 20 years) and integrated with localized CMIP6 climate change projections (~2050 timeframe) to provide an appropriate margin or range of outcomes for the next 4 decades
- As part of this analysis, EPRI will summarize a number of possible extreme weather events in the New England region
  - For example, this could be for single day, 3-day or 5-day events by mean temperature, at an aggregate or city level
- Final deliverable for this task will include extreme weather events to model, and associated probabilistic distributions

Scope of Work – Step 2: Scenario Generation

- The objective of this step is to identify power system scenarios of interest using probabilistic techniques
- Key inputs for this phase include the following:
  - Agreement on macro assumptions about future energy mix, demand composition and other high-level factors
  - Identification of risk factors associated with each resource type (e.g., wind speed, temperature and age for wind power, streamflow for hydro, outages for synchronous machines, availability of natural gas etc.)
- For each of these risk factors, a model will be developed that suitably characterizes the risk associated with that risk factor (e.g., wind power conversion curve, forced outage failure rates)

Scope of Work – Step 2: Scenario Generation, continued

- Data from weather modeling, together with additional power system data, will be translated to various power system variables – wind/solar output, load, generator availability
  - This will include impact of extreme weather on output of resources
- The various power system variables, along with the risk models will be used to develop scenarios of interest, using Monte Carlo simulation
- These scenarios will be developed via a 'scenario engine' tool that will be built by EPRI

Scope of Work – Step 3: Assessing Energy Security/Adequacy

- Initially as part of this project, the ISO will use its 21 day Energy Security Analysis tool to assess operational impacts
- By limiting the analysis to 21 days, and furthermore, applying the probabilistic scenarios developed in the prior step, the ISO expects to quantify the operational impact of extreme weather events using probabilistic risk metrics, reducing the use of engineering judgement
- As a longer term effort (beyond 18 months), to provide a comprehensive assessment of energy adequacy for different time frames and weather conditions, new adequacy study methodologies are required
- These changes are a key focus of EPRI's "Resource Adequacy for a Decarbonized Future" supplemental project, which plans to develop methods to better account for tail risk in adequacy studies
  - For example, this may include methods to run Monte Carlo simulations and make appropriate draws to ensure such events are included in chronological adequacy studies using production cost modeling approaches

Draft Timeline

- This is a draft timeline, and subject to other priorities over the course of the next year
  - Feedback may add to the scope of work, which will likely extend the timeline into early 2023
- Q4 2021 – Initiate project
- Q1 2022 – Initiate stakeholder process on Extreme Weather Modeling
- Q2 2022 – Finalize Weather Modeling scenarios
- Q2 2022 – Initiate stakeholder process on Study Scenarios
- Q4 2022 – Finalize Scenarios for operational assessment
- Q4 2022 – Preliminary results of operational assessment

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Paul Belval and Pat Gerity, NEPOOL Counsel

DATE: September 30, 2021

RE: ISO New England Inc. ("ISO") 2022 Operating and Capital Budgets
New England States Committee on Electricity ("NESCOE") 2022 Budget

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At its October 7, 2021 meeting, the Participants Committee (the "NPC") will be asked to vote on the ISO's proposed 2022 operating and capital budgets (collectively, the "ISO Budgets") and on NESCOE's 2022 operating budget (the "NESCOE Budget"). We have included with this memorandum and will post with the composite for this meeting background materials regarding these budgets.

The ISO 2022 Budgets

The ISO Budgets were prepared according to the processes included in the Participants Agreement and in the Settlement Agreement with state agencies in FERC Dockets Nos. ER13-185 and ER13-192. The ISO presented its preliminary budgets to NECPUC in early June and at the June 24 NPC Meeting. The ISO next presented the ISO Budgets to the New England state agencies and attorneys general on August 6 and to the NEPOOL Budget and Finance Subcommittee (the "Subcommittee") on August 9. Mr. Ludlow also provided a written overview of the ISO Budgets with the materials for the September 2 NPC meeting and offered to answer any questions that NPC members may have on the ISO Budgets. Questions on the ISO Budgets provided by certain New England state regulators and consumer advocates, as well as the ISO's responses thereto, are posted on the ISO's website and were included with the materials for the September 2 NPC meeting.

Included with this memorandum is a memorandum from Mr. Ludlow describing the changes that have been made to the ISO Budgets from the versions reviewed by the Subcommittee and provided previously to the NPC. That memorandum includes a link to the updated ISO Budgets presentation and a link to the comments from the New England state regulators and consumer advocates and the ISO's response to those comments. The ISO's September 24 memorandum regarding the allocation of its projected costs among the ISO Tariff Schedules is also included with this memorandum.[1]

The 2022 ISO operating budget, prior to true-ups, reflects a 4.9 percent increase over the 2021 operating budget (which is $100,000 lower than the draft operating budget last provided to the Subcommittee and to the NPC). After accounting for the true-up mechanism in the ISO Tariff, the

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[1] The memo addressing the Projected 2022 Revenue Requirement, including the final true-up for 2020 and a comparison to the 2021 Revenue Requirement, a Draft 2022 Revenue Requirement by activity, and Draft 2022 Rate Components, was circulated by the ISO to Participants Committee members and alternates and Budget & Finance Subcommittee members on September 24.

revenue requirement to fund the 2022 operating budget (i.e., the amount collected under the ISO administrative cost tariff) will increase by 5.4 percent over the amount projected to be collected in 2021. The ISO capital budget for 2022 is $32 million. This reflects a $4 million increase over the amount of the 2021 capital budget.

The following form of resolution can be used by the NPC on this matter:

> RESOLVED, that the Participants Committee supports the Year 2022 operating budget and capital budget proposed by the ISO, as presented at this meeting.

The NESCOE 2022 Budget

Ms. Heather Hunt, the Executive Director of NESCOE, joined the Subcommittee's August 9 meeting and informed the Subcommittee that NESCOE expected the NESCOE Budget for 2022 to be approximately $2,485,156, less than the $2,617,642 included in the five-year *pro forma* projections supported by the NPC in June 2017 and accepted by the FERC. NESCOE's August 9 presentation to the Subcommittee was included with the materials for the September 2 NPC meeting and Ms. Hunt offered to answer any questions that NPC members may have on the NESCOE Budget. A revised summary presentation regarding the NESCOE Budget, which reflects the actual 2022 Schedule 5 Rate as calculated by the ISO ($0.00736 per kW-mo.), rather than an estimate rate, is included with this memorandum. The revised presentation is identical to the NESCOE August 9, 2021 presentation, with only slide 12 updated and marked to reflect the final 2022 Network Load factor and final Schedule 5 Rate.

The following form of resolution can be used by the NPC in its consideration of the proposed 2022 NESCOE Budget:

> RESOLVED, that the Participants Committee supports the 2022 NESCOE budget, as proposed by NESCOE at this meeting, as the Year 2022 operating budget for NESCOE.

cc: R. Ludlow
C. Arnold
H. Hunt
NEPOOL Budget and Finance Subcommittee

memo

To: NEPOOL Participants Committee

From: Robert C. Ludlow, VP & CFO

Date: September 29, 2021

Subject: ISO New England's 2022 Proposed Operating and Capital Budgets

This 2022 operating and capital budgets (the "Budgets") update is intended to provide the NEPOOL Participants Committee with information regarding the changes that have been made to the ISO's 2022 proposed Budgets since the last review of the Budgets at the September 2, 2021 NEPOOL Participants Committee ("NPC") meeting.

Summary of Changes

The 2022 operating budget, including depreciation and excluding the true-up has been reduced to $215.1M, which is a decrease of $0.1M from the operating budget presented to the NEPOOL Budget and Finance ("B&F") Subcommittee in August and to the NPC in September. Updates have been made for final medical renewal and NERC dues amounts, which resulted in lower than estimated costs, and an increase in consulting work for the development of a market monitoring dashboard for which previous estimates have now been finalized. In addition, the Compensation and Human Resources Committee of the ISO's Board of Directors approved the 2022 proposed compensation increases, which are included in the operating budget (this approval did not change the proposed Budgets).

In summary, the 2022 operating budget, excluding the true-up, is an increase of 4.9% or $10.1M as compared to the 2021 operating budget. The 2022 operating budget, including the true-up, results in a 5.4% increase to the Revenue Requirement compared to 2021.

The 2022 overall capital budget of $32.0M has not changed from the amount presented at the August and September B&F and NPC meetings, respectively. Although the total capital budget for 2022 remains the same, there were changes to the following capital projects: the E-Mail List Server Technology Refresh and Total Transfer Capability Calculator Redesign projects have moved from the planning phase to chartered and have changes in the 2022 and the overall project budgets; there is a reallocation of costs between 2021 and 2022 or other immaterial adjustments for the nGEM Software Development Part II, Security Information and Event Management Log Monitoring Replacement, Integrated Market Simulator Phase I, TranSMART Technical Architecture Update, and Replacement of Locational Marginal Price Monitor projects. The 2022 Other Emerging Work balance was adjusted to reflect the funding changes to the foregoing projects. In addition, adjustments were made to the 2021 and overall project budgets for the Amazon Web Services Cloud Foundation and Linear State Estimator projects with no changes for 2022 estimated costs.

Budget materials have also been updated to clarify that the gross 2022 full-time equivalent ("FTE") positions are 622.5, with funding included for 593.0 FTEs. The 593 is based on the recruitment of 14 additional 2022 positions but only full funding of 9 FTEs because onboarding is expected to occur throughout the year. All other positions are budgeted with an estimated 4.0% vacancy.

Finally, we have made updates to clarify the content on a number of pages and the ISO/RTO Financial Summary for 2020 was updated. Changes by category and slide page number are identified below.

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Materials

The August 9, 2021 budget presentation (the "Budget Presentation") presented to the NEPOOL B&F Subcommittee has been updated to reflect the changes described above. The updated Budget Presentation can be found at the following link: https://www.iso-ne.com/static-assets/documents/2021/09/06_isone_proposed_2022_op_ca_budget_update_09_29_2021.pdf

The 2022 state agencies' written comments and the accompanying response can be found at the following link: https://www.iso-ne.com/static-assets/documents/2021/09/06_states_2022_budget_comments_isone_response.pdf

Budget Presentation Slide Changes

The following pages have been updated in the Budget Presentation for the changes noted.

Operating Budget Slide page changes:

- To reflect budget changes, as noted above, for final medical renewal amounts, final NERC dues amounts, and for the development of a market monitoring dashboard: 15, 17, 19, 21, 23, 26, 50, 52, 53, 54, 58, 59, 60, 61, 62, 63, 64, 79, 91, 93, 102, 104, 105, 108, 109, 152

- To reflect gross headcount of 622.5 FTEs: 80, 92, 94, 97, 100, 106, 111

- To reflect updated compensation survey data: 70

- Other clarifying or miscellaneous changes: 24, 86

Capital Budget Slide page changes: 41, 42, 43, 119, 121, 128, 129, 144, 146

In addition, Slide 158 (ISO/RTO Financial Summary for 2020) was updated to add ERCOT financial information that is now available.

Please let me know if you have any questions in advance of our meeting. I look forward to our discussion.

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memo

To: NEPOOL Budget & Finance Subcommittee and Participants Committee

From: Bob Ludlow and Cheryl Arnold

Date: September 24, 2021

Subject: Projected 2022 Revenue Requirement for ISO New England Administrative Cost Tariff Schedules

To help our Participants prepare their 2022 budgets and consistent with information provided in previous years, this memo includes a preliminary indication of ISO-NE's 2022 costs and related tariff schedules. Specifically, the memo includes (1) the estimated 2022 Revenue Requirement, including the final true-up for 2020 and a comparison to the 2021 Revenue Requirement (see Exhibit 1 below), (2) the Draft 2022 Revenue Requirement by activity (see Exhibit 2), and (3) the Draft 2022 Rate Components (see Exhibit 3). Both Exhibits 2 and 3 are attached and, in their final form, will be part of the ISO's budget filing with FERC. The cost assignment and allocation mechanisms that were utilized in the Draft 2022 tariff schedules were established as part of the settlement that has been in effect for the last twenty years.

Overall Change in Revenue Requirement

As shown in Exhibit 1 below, the overall Revenue Requirement has increased by $11.0 million year-over-year, from $205.1M for 2021 to $216.1M for 2022.[1] The change includes a $10.1 million increase in the revenue requirement before taking into account the change in prior year true-ups. Prior year true-ups resulted in an increase of $0.9M. The 2021 tariff included a $0.2M revenue requirement increase for the final 2019 true-up, while the 2022 tariff will include an increase of $1.1M as a result of the final 2020 true-up.

Draft Exhibit 1
ISO New England
Revenue Requirement By Tariff Schedule
2022 Estimated Amount vs. 2021 Filed Amount

	Sch 1	Sch 2	Sch 3	Total
2022 Revenue Requirement Before Prior Year True Ups	$ 45,082,953	$ 105,115,206	$ 64,872,524	$ 215,070,683
2021 Revenue Requirement Before Prior Year True Ups	43,558,799	99,301,285	62,103,185	204,963,269
$ Increase/(Decrease) from 2021 to 2022	**1,524,154**	**5,813,921**	**2,769,339**	**10,107,414**
% Increase/(Decrease) from 2021 to 2022	**3.5%**	**5.9%**	**4.5%**	**4.9%**
2022 Revenue Requirement Prior Year True Ups-Under/(Over) Collect	$ (701,273)	$ 1,037,876	$ 734,687	$ 1,071,290
2021 Revenue Requirement Prior Year True Ups-Under/(Over) Collect	(1,447,780)	759,504	839,312	151,036
$ Increase/(Decrease) from 2021 to 2022	**746,507**	**278,372**	**(104,625)**	**920,254**
2022 Revenue Requirement Including Prior Year True-Ups	$ 44,381,680	$ 106,153,082	$ 65,607,211	$ 216,141,973
2021 Revenue Requirement Including Prior Year True-Ups	42,111,019	100,060,789	62,942,497	205,114,305
$ Increase/(Decrease) from 2021 to 2022	**2,270,661**	**6,092,293**	**2,664,714**	**11,027,668**
% Increase/(Decrease) from 2021 to 2022	**5.4%**	**6.1%**	**4.2%**	**5.4%**

[1] Minor variances may appear due to rounding among the various presentations and schedules for the 2022 Budgets.

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Change in Revenue Requirement by Schedule

Before true-ups in 2022 and 2021, the 2022 Revenue Requirement reflects an overall increase of \$10.1M or 4.9% over the 2021 Revenue Requirement. By tariff schedule, the changes are: Schedule 1, a \$1.5M or 3.5% *increase*; Schedule 2, a \$5.8M or 5.9% *increase*; and Schedule 3, a \$2.8M or 4.5% *increase*.

The Tariff Schedule 1 increase of \$1.5M is attributable to:

- Increases that impact all three schedules, including for compensation and employee benefit costs, computer services and systems support, cyber security systems and resources, power system modeling, and an increase in the operating contingency for targeted areas of importance to the region (the uses of the operating contingency are still in planning and it is unpredictable as to the exact level of funding that will be required).
- For Legal and Transmission Planning resources to facilitate studying the states' long term goals of transitioning to a carbon free power system and to provide information beyond a 10-year planning horizon in alignment with the states' long term vision.
- Partially offsetting the increases were decreases that impact all three schedules, including lower employee salary rates, lower Post-Retirement Medical Plan funding and reduced Pension Benefit Guarantee Corporation Premiums, and software licensing costs for replaced technology.

The Tariff Schedule 2 increase of \$5.8M is attributable to:

- Funding for items that impact all three schedules, partially offset by decreases that impact all three schedules, as noted above in the explanation for Schedule 1.
- Funding for items that impact Schedules 2 and 3, including resources to address Pathways to the Future Grid work, to integrate distributed resources into the wholesale energy market in compliance with FERC Order 2222, and for Resource Capacity Accreditation.
- Funding for Legal and Market Development resources to support workload levels for the implementation of energy market design changes.

The Tariff Schedule 3 increase of \$2.8M is attributable to:

- Funding for items that impact all three schedules, partially offset by decreases that impact all three schedules, as noted above in the explanation for Schedule 1.
- Funding for items that impact Schedules 2 and 3, as noted above in the explanation for Schedule 2.
- Funding for work related to changes in the Minimum Offer Price Rule for the Forward Capacity Market, and for increased dues for the North American Electric Reliability Corporation and the Northeast Power Coordinating Council.
- Partially offsetting the Schedule 3 increases is a reduction of funding for the updating of Cost of New Entry (CONE), Net CONE, and Offer Review Trigger Price in the Forward Capacity Market that was completed in 2021.

The ISO 2022 Revenue Requirement will be reviewed and voted on at the October 7, 2021 NPC meeting. Should you have any questions regarding the information provided in this memo, do not hesitate to contact us.

Exhibit 2
Page 1 of 6

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Line No.	Activity Code No.	Activity Code Description	Allocation Factor (1)	Self-Funding Tariff Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**Administration-CEO**					
2	12651	Indirect Administrative Support	Total Dir Labor	$ 10,233,161	$ 2,205,246	$ 5,295,661	$ 2,732,254
3	12652	NEPOOL Committee Support	Total Dir Labor	3,000	647	1,553	801
4	12654	National Committee Support	Total Dir Labor	1,950	420	1,009	521
5	12657	Indirect Administrative Support for BCC	Total Dir Labor	1,084,227	233,651	561,088	289,489
6		Total		11,322,338	2,439,964	5,859,310	3,023,064
7							
8		**Finance**					
9	11601	Payroll Administration	Total Dir Labor	536,908	115,704	277,850	143,355
10	11701	Accounts Payable	Total Dir Labor	345,813	74,523	178,958	92,332
11	11702	Procurement	Total Dir Labor	475,782	102,531	246,217	127,034
12	11901	Settle for Power Transactions	Total Dir Labor	86,353	18,609	44,688	23,056
13	12001	Budgeting and Forecasting	Total Dir Labor	561,296	120,959	290,471	149,866
14	12005	Credit Administration	Total Dir Labor	474,943	102,350	245,783	126,810
15	12101	Ledger Closing, Financial Statements and Tax Reporting	Total Dir Labor	561,296	120,959	290,471	149,866
16	12201	Treasury and Cash Management	Total Dir Labor	2,420,481	521,614	1,252,599	646,269
17	92004	Depreciation Expense 2004 Assets	Alloc-Fixed	43,160	8,988	22,535	11,637
18	92005	Depreciation Expense 2005 Assets	Alloc-Fixed	773,169	163,467	402,126	207,577
19	92006	Depreciation Expense 2006 Assets	Total Dir Labor	568,947	122,608	294,430	151,909
20	92007	Depreciation Expense 2007 Assets	Total Dir Labor	156,825	33,796	81,157	41,872
21	92008	Depreciation Expense 2008 Assets	Total Dir Labor	2,677	577	1,385	715
22	92009	Depreciation Expense 2009 Assets	Total Dir Labor	1,535	331	794	410
23	92010	Depreciation Expense 2010 Assets	Total Dir Labor	2,380	513	1,232	635
24	92011	Depreciation Expense 2011 Assets	Total Dir Labor	-	-	-	-
25	92012	Depreciation Expense 2012 Assets	Total Dir Labor	82,399	17,757	42,641	22,001
26	92013	Depreciation Expense 2013 Assets	Total Dir Labor	859,069	185,129	444,568	229,371
27	92014	Depreciation Expense 2014 Assets	Alloc-Fixed	164,367	29,995	97,209	37,163
28	92015	Depreciation Expense 2015 Assets	Alloc-Fixed	36,437	7,852	18,856	9,729
29	92016	Depreciation Expense 2016 Assets	Alloc-Fixed	197,121	46,958	121,004	29,160
30	92017	Depreciation Expense 2017 Assets	Alloc-Fixed	480,742	108,618	292,393	79,731
31	92018	Depreciation Expense 2018 Assets	Alloc-Fixed	2,259,745	432,822	1,185,762	641,161
32	92019	Depreciation Expense 2019 Assets	Alloc-Fixed	7,202,973	1,215,829	3,980,684	2,006,460
33	92020	Depreciation Expense 2020 Assets	Alloc-Fixed	6,846,161	977,596	3,600,862	2,267,704
34	92021	Depreciation Expense 2021 Assets	Alloc-Fixed	5,195,737	821,641	2,753,730	1,620,366
35	92022	Depreciation Expense 2022 Assets	Alloc-Fixed	1,040,569	219,189	527,703	293,677
35	99707	Amortization of Land Recovery	Alloc-Fixed	39,300	2,460	24,170	12,670
36	99995	NPCC/NERC Dues	Alloc-Fixed	6,445,517	-	-	6,445,517
37	99996	Operating Contingency	Total Dir Labor	700,000	150,850	362,250	186,900
38	99996	Operating Contingency	Total Dir Labor	2,000,000	431,000	1,035,000	534,000
39	99998	Payroll & Other Accruals	Total Dir Labor	14,171,513	3,053,961	7,333,758	3,783,794
40		Total		54,733,216	9,209,185	25,451,285	20,072,745
41							
42		**Facilities & Security**					
43	12664	Building Maintenance	Total Dir Labor	3,275,302	705,828	1,694,969	874,506
44		Total		3,275,302	705,828	1,694,969	874,506
45							
46		**Enterprise Risk Management**					
47	22704	Record Retention Services	Alloc-Fixed	52,631	17,526	17,526	17,579
48	22705	Corporate Scorecard	Alloc-Fixed	55,473	18,473	18,473	18,528
49	22706	Document Management Services	Alloc-Fixed	158,495	63,398	47,549	47,549
50	22709	Management	Total Dir Labor	23,774	5,123	12,303	6,348
51	22710	Employee Development	Total Dir Labor	4,514	973	2,336	1,205
52	22714	Analysis	Total Dir Labor	345,413	74,436	178,751	92,225
53	22721	Corp Strategic Risk	Total Dir Labor	298,683	64,366	154,569	79,748
54	22726	Project Risk Mngmt Meeting	Total Dir Labor	15,850	3,416	8,202	4,232
55	23006	Business Continuity Planning	Total Dir Labor	224,939	48,474	116,406	60,059
56	25011	Corrective Action/Preventive Action	Alloc-Fixed	289,054	96,255	96,255	96,544
57	25014	EtQ Tools Dev & Support	Total Dir Labor	43,757	9,430	22,644	11,683
58	25015	Coord Tariff Chg Comm (TCC)	Total Dir Labor	3,962	854	2,051	1,058
59		Total		1,516,546	402,724	677,064	436,758
60							
61		**Human Resources**					
62	12661	Employee Affairs (Recreation Committee)	Total Dir Labor	55,419	11,943	28,679	14,797
63	12701	Recruiting/Interviewing	Total Dir Labor	695,841	149,954	360,098	185,790
64	12702	Intern Expense	Total Dir Labor	376,979	81,239	195,087	100,654
65	12801	Employee Relations	Total Dir Labor	2,513	541	1,300	671
66	12901	Benefit Administration	Total Dir Labor	1,324,945	285,526	685,659	353,760
67	12951	Compensation	Total Dir Labor	575,781	124,081	297,967	153,734
68	12961	HR - General	Total Dir Labor	1,287,486	277,453	666,274	343,759
69	12962	HR - Training	Total Dir Labor	1,334,797	287,649	690,758	356,391
70	13301	HR - Labor Relations	Total Dir Labor	600	129	311	160
71	13410	Power Training & Development	Total Dir Labor	1,735,968	374,101	898,364	463,504
72	13411	Markets Training & Development	Total Dir Labor	64,323	13,862	33,287	17,174
73	13412	People Training & Development	Total Dir Labor	435,352	93,818	225,295	116,239
74	13413	Business Skills Training & Development	Total Dir Labor	215,594	46,461	111,570	57,564
75	13414	Technology Training & Development	Total Dir Labor	1,368,390	294,888	708,142	365,360
76		Total		9,473,989	2,041,645	4,902,789	2,529,555

Exhibit 2
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Line No.	Activity Code No.	Description	Allocation Factor (1)	Self-Funding Tariff Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**Legal Department**					
2	12422	Interconnection Queue	Alloc-Fixed	122,972	-	-	122,972
3	12502	Board of Directors	Total Dir Labor	185,609	39,999	96,053	49,558
4	12508	Energy Markets / Complaints / Rule Changes	Alloc-Fixed	2,107,995	-	2,107,995	-
5	12513	Miscellaneous Labor Matters	Total Dir Labor	137,500	29,631	71,156	36,713
6	12514	NEPOOL Participants Committee	Total Dir Labor	93,202	20,085	48,232	24,885
7	12517	Administrative and Clerical Support	Total Dir Labor	614,861	132,503	318,191	164,168
8	12543	Independent Market Advisor	Alloc-Fixed	1,100,000	-	770,000	330,000
9	12559	General Corporate	Total Dir Labor	1,702,836	366,961	881,218	454,657
10	12584	Installed Capacity Requirements	Total Dir Labor	20,495	-	-	20,495
11	12587	Capacity Market Development	Alloc-Fixed	529,209	-	-	529,209
12	12588	Web Content Management	Total Dir Labor	754,545	162,605	390,477	201,464
13	12606	GC - NERC	Alloc-Fixed	600	270	60	270
14	12619	Compliance	Alloc-Fixed	122,972	49,189	49,189	24,594
15	12622	Open Access Transmission Tariff	Alloc-Fixed	359,483	359,483	-	-
16	12623	Reliability Standards	Alloc-Fixed	20,495	-	4,099	16,396
17	12663	Public Information	Total Dir Labor	1,547,756	333,542	800,964	413,251
18	12669	Government Affairs	Total Dir Labor	1,778,121	383,185	920,177	474,758
19		Total		11,198,652	1,877,452	6,457,811	2,863,390
20							
21		**Internal Audit**					
22	15001	Indirect Management Duties	Total Dir Labor	149,540	32,226	77,387	39,927
23	15002	Personnel Management	Total Dir Labor	35,762	7,707	18,507	9,548
24	15003	Budget & Forecasting	Total Dir Labor	35,762	7,707	18,507	9,548
25	15004	Audit Follow-up Activities	Total Dir Labor	59,603	12,845	30,845	15,914
26	15005	Audit & Finance Committee	Total Dir Labor	89,739	19,339	46,440	23,960
27	15006	Internal Audit Business Process Update	Total Dir Labor	11,921	2,569	6,169	3,183
28	15007	Annual Audit Work Plan	Total Dir Labor	125,501	27,046	64,947	33,509
29	15011	Internal Audit Meetings	Total Dir Labor	11,921	2,569	6,169	3,183
30	15013	Indirect Adminstrative Support	Total Dir Labor	53,977	11,632	27,933	14,412
31	15014	GRC Tool Admin and Development	Total Dir Labor	239,021	51,509	123,694	63,819
32	15021	Performance Measurements	Total Dir Labor	23,841	5,138	12,338	6,366
33	15022	Vendor Contracts	Total Dir Labor	11,921	2,569	6,169	3,183
34	15023	Wire Transfers	Total Dir Labor	11,921	2,569	6,169	3,183
35	15029	Payroll	Total Dir Labor	11,921	2,569	6,169	3,183
36	15031	Employee Expense Reporting	Total Dir Labor	11,921	2,569	6,169	3,183
37	15040	Operations	Total Dir Labor	190,731	41,102	98,703	50,925
38	15085	Information Technology	Total Dir Labor	229,921	49,548	118,984	61,389
39	15110	Systems Development Reviews	Total Dir Labor	71,524	15,413	37,014	19,097
40	15133	Satellite Operations Reviews	Total Dir Labor	24,765	5,337	12,816	6,612
41	15137	Satellite IT Reviews	Total Dir Labor	925	199	479	247
42	15161	External Audit- Pension Audit	Total Dir Labor	72,036	15,524	37,279	19,234
43	15162	External Audit- Financial Audit	Total Dir Labor	132,528	28,560	68,583	35,385
44	15166	External Audit -Pricing Module Certification	Alloc-Fixed	10,041	-	10,041	-
45	15176	External Audit - ISO Internet Vulnerability Assessment	Total Dir Labor	10,040	2,164	5,196	2,681
46	15186	External Audit - SSAE 18 Direct Support	Total Dir Labor	59,603	12,845	30,845	15,914
47	15192	Data Mining - Audit Command Language Implementation	Total Dir Labor	45,450	9,794	23,520	12,135
48	25702	External Audit - SSAE 18 Direct Management	Alloc-Fixed	577,993	-	577,993	-
49	28005	Fraud, Waste & Abuse Program	Total Dir Labor	11,921	2,569	6,169	3,183
50	28007	Contractor/Consultant Review	Total Dir Labor	24,041	5,181	12,441	6,419
51	28159	Audit - Oracle Licensing Compl	Total Dir Labor	99,990	21,548	51,745	26,697
52	28162	Audit-Virtual Desktop Infrastr	Total Dir Labor	99,990	21,548	51,745	26,697
53	28178	Third Party Cyber Risk Management Process Review	Total Dir Labor	18,181	3,918	9,409	4,854
54		Total		2,563,952	425,810	1,610,572	527,570
55							
56		**COO-Adm**					
57	19001	NEPOOL Committee Support	Total OPS Labor	209,358	56,108	100,387	52,863
58	19005	Indirect Supervision/Clerical Support	Total OPS Labor	2,315,098	620,446	1,110,089	584,562
59	19009	Renewable Resource Integration	Alloc-Fixed	149,936	-	-	149,936
60		Total		2,674,391	676,554	1,210,476	787,361
61							
62		**System Operations & Market Administration**					
63	14404	NEPOOL Committee Support	SOA Labor	18,232	6,297	8,463	3,471
64	14405	Indirect Supervision/Clerical Support	SOA Labor	472,310	163,136	219,246	89,928
65	14407	Regional Committee Support	SOA Labor	13,674	4,723	6,348	2,604
66	14408	National Committee Support	SOA Labor	38,674	13,358	17,953	7,364
67	19101	NEPOOL Committee Support	MOA Labor	73,080	-	51,156	21,924
68		Total		615,971	187,515	303,166	125,290

Exhibit 2
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Line No.	Activity Code No.	Activity Code Description	Allocation Factor (1)	Self-Funding Tariff Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**Operations**					
2	14001	Generation Dispatch	Alloc-Fixed	3,424,779	-	2,876,814	547,965
3	14002	Transmission Operations	Alloc-Fixed	3,424,779	2,739,823	171,239	513,717
4	14304	Advanced Scheduling and Forecasting	Alloc-Fixed	2,382,848	119,142	1,882,450	381,256
5	14402	Operations Training	Alloc-Fixed	3,331,413	1,332,565	1,332,565	666,283
6	14413	Operations Support Training & Development	Alloc-Fixed	135,000	54,000	54,000	27,000
7	14563	National Committee Support	OPS Labor	17,109	4,784	9,471	2,854
8	14564	Indirect Supervision/Clerical Support	OPS Labor	1,358,140	379,736	751,866	226,538
9	14565	Employee Development	OPS Labor	50,718	14,181	28,077	8,460
10	14702	Procedure Documentation	Alloc-Fixed	73,172	29,269	29,269	14,634
11		Total		14,197,956	4,673,499	7,135,752	2,388,705
12							
13		**Reliability and Operations Compliance**					
14	14803	Regional Committee Support	OS Labor	77,532	38,766	-	38,766
15	14804	National Committee Support	OS Labor	101,732	50,866	-	50,866
16	14806	Employee Development	Alloc-Fixed	48,781	27,098	9,429	12,254
17	14807	NERC RSAW Update and Audit Prep	Alloc-Fixed	147,330	73,665	-	73,665
18	14808	Change Management	Alloc-Fixed	24,391	10,976	2,439	10,976
19	14809	Tariff Compliance	Alloc-Fixed	182,930	54,879	109,758	18,293
20	14812	NPCC MP Referral	Alloc-Fixed	60,977	24,391	24,391	12,195
21	14815	Identifications and Description of Internal Controls	Total Dir Labor	487,814	105,124	252,444	130,246
22	14816	Support NE Compliance Groups	Total Dir Labor	60,977	13,140	31,555	16,281
23	14817	AskISO Customer or Internal Inquiries	Total Dir Labor	60,977	13,140	31,555	16,281
24		Total		1,253,441	412,046	461,572	379,823
25							
26		**Operations Support Services**					
27	14301	Contract Administration and Scheduling	Alloc-Fixed	(60,000)	(6,000)	(42,000)	(12,000)
28	14453	National Committee Support	TSO Labor	338,408	109,543	161,793	67,072
29	14454	Indirect Supervision/Clerical Support	TSO Labor	20,610	6,671	9,854	4,085
30	14467	Nuclear Plant Liaison	Alloc-Fixed	17,109	-	-	17,109
31	14477	Participant project and outage coordination support	Alloc-Fixed	17,109	8,554	-	8,554
32	14765	GRIDEX - Grid Exercise	Alloc-Fixed	51,774	25,887	-	25,887
33	18361	Transmission Studies, Operations, OASIS Support	Alloc-Fixed	2,796,340	2,237,072	139,817	419,451
34	18381	Transmission Outage Application - Short Term	Alloc-Fixed	1,134,930	907,944	56,746	170,239
35	18382	Transmission Outage Application - Long Term	Alloc-Fixed	734,930	-	-	734,930
36		Total		5,051,209	3,289,671	326,210	1,435,327
37							
38		**Market Monitoring**					
39	16101	Market Power Monitoring and Mitigation	Alloc-Fixed	4,896,768	-	3,427,737	1,469,030
40	16115	Analysis & Internal Reports	Alloc-Fixed	324,705	-	227,294	97,412
41	16121	FCM Market Monitoring	Alloc-Fixed	17,878	-	-	17,878
42		Total		5,239,351	-	3,655,031	1,584,320
43							
44		**Market & Resource Administration**					
45	21901	Day Ahead Market Administration	Alloc-Fixed	309,325	-	309,325	-
46	21902	Real Time Price Verification	Alloc-Fixed	309,325	-	309,325	-
47	21904	NEPOOL Committee Support	MA Labor	1,036	-	1,003	33
48	21907	Indirect Supervision/Clerical Support	MA Labor	580,511	-	562,166	18,344
49	21908	Employee Development	MA Labor	116,000	-	112,334	3,666
50	21909	Customer Support	MA Labor	510	-	494	16
51	21913	Data Collection/Report Writing	Alloc-Fixed	231,994	-	231,994	-
52	21915	FTR/Auction Administration	Alloc-Fixed	347,991	173,995	173,995	-
53	21916	Forward Reserve Market - Administration	Alloc-Fixed	38,666	-	-	38,666
54	21917	Real Time Price Finalization	Alloc-Fixed	231,994	-	231,994	-
55	21951	FCM Annual Reconfiguration Auction Administration	Alloc-Fixed	77,331	-	-	77,331
56	21953	FCM Monthly Administration	Alloc-Fixed	115,997	-	-	115,997
57		Total		2,360,679	173,995	1,932,631	254,052

Exhibit 2
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DRAFT

Line No.	Activity Code No.	Description	Allocation Factor (1)	Self-Funding Tariff Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**Market Analysis & Settlements**					
2	1701	Billing Statements - Energy	Alloc-Fixed	91,582	-	91,582	-
3	1702	Billing Statements - Transmission	Alloc-Fixed	109,458	109,458	-	-
4	1713	Billing Statements - ISO Tariff	Total Dir Labor	12,978	2,797	6,716	3,465
5	1714	Billable Tariff Re-billings	Total Dir Labor	1,224	1,224	-	-
6	2047	Score Card	STLM Labor	3,183	471	1,551	1,162
7	2048	FCM	Alloc-Fixed	270,094	-	-	270,094
8	2049	Product Testing	Alloc-Fixed	16,651	-	13,321	3,330
9	2051	Legal Support	Alloc-Fixed	7,101	-	3,551	3,551
10	2005	Customer Service	STLM Labor	184,455	27,281	89,848	67,326
11	2007	Admin support - NEPOOL Committees	STLM Labor	1,135	168	553	414
12	2009	Indirect Supervision/Clerical Support	STLM Labor	845,320	125,023	411,755	308,542
13	2010	Employee Development	STLM Labor	182,696	27,021	88,991	66,684
14	2013	FTR Administration	Alloc-Fixed	35,996	-	35,996	-
15	2014	Billing Statements - NCPC	Alloc-Fixed	376,369	-	188,184	188,184
16	2020	Billing Disputes	Total Dir Labor	19,345	4,169	10,011	5,165
17	2021	Analysis & Reporting	Total Dir Labor	414,206	89,261	214,352	110,593
18	2024	ASM Regulation	Alloc-Fixed	27,915	-	-	27,915
19	2025	ASM Locational Forward Reserve	Alloc-Fixed	107,989	-	-	107,989
20	2026	Batch Processing	Total Dir Labor	33,792	7,282	17,488	9,023
21	2032	Billing	STLM Labor	41,139	6,084	20,039	15,016
22	2033	Market Analysis	Alloc-Fixed	141,597	-	141,597	-
23		Total		2,924,226	400,239	1,335,534	1,188,453
24							
25		**Market Operations Support Services**					
26	3000	Hourly Settlements Support	Alloc-Fixed	264,675	-	132,338	132,338
27	3002	Monthly Settlements Support	Alloc-Fixed	145,663	72,832	-	72,832
28	3003	Market Analysis Support	Alloc-Fixed	203	-	203	-
29	3004	Generation & Load Admin Support	Alloc-Fixed	21,158	-	21,158	-
30	3006	Customer Service	Alloc-Fixed	111,282	-	111,282	-
31	3008	Admin Support	Alloc-Fixed	244,094	-	244,094	-
32	3009	Indirect Supervision (Principal Analysts only)	Alloc-Fixed	144,646	-	144,646	-
33	3010	Employee Development	Alloc-Fixed	19,327	-	19,327	-
34	3012	FERC Data Request	Alloc-Fixed	3,865	-	3,865	-
35	3015	Market Administration Support	Alloc-Fixed	814	-	814	-
36	3016	Market Monitoring Assistance	Alloc-Fixed	1,831	-	1,831	-
37	3017	Project MAS (Market Analysis & Settlements)	Alloc-Fixed	289,495	72,374	72,374	144,748
38	3018	Project MRA (Market and Resource Administration)	Alloc-Fixed	2,848	-	2,848	-
39		Total		1,249,901	145,205	754,779	349,917
40							
41		**Market Services**					
42	16001	Participant/membership support	Alloc-Fixed	45,493	-	22,747	22,747
43	16006	Call Support (Ask ISO)	Alloc-Fixed	1,340,787	348,605	884,919	107,263
44	16414	Direct Customer Contact	MS Labor	48,387	-	43,548	4,839
45	16419	Asset Registration Implemented	Alloc-Fixed	309,325	-	309,325	-
46	16420	Asset Registration Review	Alloc-Fixed	154,663	-	154,663	-
47	16422	Claimed Capability Audits	Alloc-Fixed	541,319	-	541,319	-
48	16425	DR Registration Implemented	Alloc-Fixed	38,666	-	38,666	-
49	16432	New Generation Coordination and Registration	Alloc-Fixed	193,328	-	193,328	-
50	16434	QMS/CAPA Process and Procedure Updates	Total Dir Labor	270,659	58,327	140,066	72,266
51		Total		2,942,627	406,932	2,328,581	207,114
52							
53		**Participant Training Services**					
54	16021	Training Development	Alloc-Fixed	657,651	-	328,825	328,825
55	16024	Training Delivery	Alloc-Fixed	2,697	-	1,348	1,348
56	16436	Mkt Trng/Cus Serv Indirect Supervision	Total Dir Labor	371,725	-	371,725	-
57		Total		1,032,072	-	701,898	330,174
58							
59		**Planning Services**					
60	14313	National Committee Support	PSR Labor	125,894	13,685	6,345	105,865
61	17101	Analysis	Alloc-Fixed	478,234	-	334,764	143,470
62	17131	Calculate Objective Capability	Alloc-Fixed	328,786	-	-	328,786
63	17231	PSR Regulatory Filings	Alloc-Fixed	29,890	-	-	29,890
64	17251	Regional Bulk Power System Assessment	Alloc-Fixed	29,890	14,945	14,945	-
65	17331	NEPOOL Committee Support	PSR Labor	59,782	6,498	3,013	50,270
66	17361	Regional Committee Support	PSR Labor	29,890	3,249	1,506	25,134
67	17401	Indirect Supervisory Activities	PSR Labor	179,340	19,494	9,039	150,807
68	17403	TCA Application Review	Alloc-Fixed	93,279	-	-	93,279
69	17405	Energy Efficiency Forecast	Alloc-Fixed	119,561	-	-	119,561
70	17408	MA - Energy Efficiency Advisory Council	Total Dir Labor	336	73	174	90
71	17409	Environmental/Emissions Supp	Total Dir Labor	29,890	-	-	29,890
72	17501	FCA - Evaluate Existing Resource De-list Bids	Alloc-Fixed	98,675	-	-	98,675
73	17502	FCA - Preliminary Review of Show of Interest Applications	Alloc-Fixed	46,644	-	-	46,644
74	17503	FCA - New Resource Qualification Support	Alloc-Fixed	851,984	-	-	851,984
75	17504	FCA - Perform Transmission / Topology Assessments	Alloc-Fixed	46,644	-	-	46,644
76	17505	FCA - Perform Existing Resource Qualification	Alloc-Fixed	46,644	-	-	46,644
77	17507	FCA - Auctions & Filings	Alloc-Fixed	1,067,625	-	-	1,067,625
78	17508	FCA - Annual Reconfiguration Auction Support/Reliability Reviews	Alloc-Fixed	69,963	-	-	69,963
79	18101	Develop Load Forecast	Alloc-Fixed	499,560	99,912	99,912	299,736
80	18121	Operations Forecast Support	Alloc-Fixed	89,669	17,934	17,934	53,801
81	18133	Solar Load Forecast Development	Alloc-Fixed	89,672	17,934	17,934	53,803
82		Total		4,411,851	193,724	505,566	3,712,561

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Line	Activity Code		Allocation	Self-Funding Tariff			
No.	No.	Description	Factor (1)	Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**System Planning**					
2	18150	Regional Transmission Expansion Plan	Alloc-Fixed	224,814	168,610	56,203	-
3	18148	NEPOOL Committee Support	Alloc-Fixed	19,397	-	19,397	-
4	18152	States Requests	Alloc-Fixed	32,878	16,439	8,220	8,220
5	18401	Regional Activities	Alloc-Fixed	32,332	32,332	-	-
6	18402	Transmission Planning/Economic Studies Initiative	Alloc-Fixed	312,559	-	156,280	156,280
7	18531	Indirect Supervision/Clerical Support	SP Labor	125,901	31,261	22,322	72,317
8	18562	Project Management	Alloc-Fixed	61,450	61,450	-	-
9		Total		809,332	310,093	262,422	236,817
10							
11		**Transmission Planning**					
12	14715	Non DOE Funded/Unallowable	Alloc-Fixed	114,226	-	-	114,226
13	18201	Transmission System Assessment	Alloc-Fixed	2,979,705	2,979,705	-	-
14	18301	NEPOOL Administrative Support - Schedule 1 Tariff	Alloc-Fixed	46,887	46,887	-	-
15	18333	General SIS/FS	Alloc-Fixed	978,843	978,843	-	-
16	18334	Indirect Supervision/Clerical Support	Alloc-Fixed	354,634	354,634	-	-
17	18335	Regulatory Activities - NPCC	Alloc-Fixed	248,366	248,366	-	-
18	18336	National Activities	Alloc-Fixed	233,311	233,311	-	-
19	18343	FERC Order 1000	Alloc-Fixed	52,036	-	-	52,036
20	18346	OATT and Oper. Agreement Dev., Adm. and Support	Alloc-Fixed	233,196	233,196	-	-
21	18350	States Future Planning Studies	Alloc-Fixed	92,175	92,175	-	-
22		Total		5,333,380	5,167,118	-	166,262
23							
24		**Program Management**					
25	801	Program Management - Administration	Total Dir Labor	632,804	136,369	327,476	168,959
26	1661	ISO Program Management	Alloc-Fixed	444,855	-	311,398	133,456
27	26051	Gov, Risk Mgt and Compl Stwr	Total Dir Labor	11,999	2,586	6,209	3,204
28		Total		1,089,657	138,955	645,084	305,619
29							
30		**Advanced Technology Solutions**					
31	21201	Advanced Technology Solutions	Total Dir Labor	3,251,012	700,593	1,682,398	868,020
32	21203	Employee Development	Total Dir Labor	34,709	7,480	17,962	9,267
33		Total		3,285,720	708,073	1,700,360	877,287
34							
35		**Market Development & Settlements Admin.**					
36	16607	National Committee Support	Total Dir Labor	71,988	15,513	37,254	19,221
37	21001	Market Development	Alloc-Fixed	1,039,234	-	519,617	519,617
38	21002	Administration	Total Dir Labor	383,983	82,748	198,711	102,523
39	21003	Employee Development	Total Dir Labor	92,599	19,955	47,920	24,724
40	21007	Budget/Forecast Support	Total Dir Labor	265,771	57,274	137,537	70,961
41	21011	Capacity Market	Alloc-Fixed	1,833,578	-	-	1,833,578
42	22402	Working Group Meetings and Support	Alloc-Fixed	30,182	-	15,091	15,091
43	22656	Energy, Reserve, and Regulation Markets	Alloc-Fixed	1,277,250	-	957,937	319,312
44	22660	Energy Security	Alloc-Fixed	841,987	-	420,994	420,994
45	22661	Project: DER Participation	Alloc-Fixed	470,478	-	235,239	235,239
46		Total		6,307,050	175,491	2,570,300	3,561,260
47							
48		**NEPOOL Relations**					
49	22602	NEPOOL Committee Meetings & Support	Alloc-Fixed	355,674	-	177,837	177,837
50	22607	NEPOOL Committee Administration	Total Dir Labor	962,195	207,353	497,936	256,906
51	22612	Future Grid Study and Modeling	Total Dir Labor	1,359,772	-	543,909	815,863
52		Total		2,677,641	207,353	1,219,682	1,250,606
53							
54		**IT Management**					
55	6517	Employee Development - Hardware/Software	Total Dir Labor	26,878	5,792	13,909	7,176
56	6519	Indirect Supervision and Clerical Support	Total Dir Labor	5,315,902	1,145,577	2,750,979	1,419,346
57	6552	Security	Total Dir Labor	459,826	99,093	237,960	122,774
58	6556	Budget Preparation, Tracking & Forecast	Total Dir Labor	100,911	21,746	52,221	26,943
59	6557	Information Technology Committee	Total Dir Labor	87,794	18,920	45,433	23,441
60	22501	Change Management Support	Alloc-Fixed	381,504	171,677	171,677	38,150
61	22505	Administrative	Alloc-Fixed	362,121	123,121	119,500	119,500
62		Total		6,734,936	1,585,925	3,391,680	1,757,330
63							
64		**IT Infrastructure Support**					
65	6510	Desktop Support - Hardware	Total Dir Labor	666,423	143,614	344,874	177,935
66	6511	Desktop Support - Software	Total Dir Labor	908,579	195,799	470,190	242,591
67	6512	Host Computer - Hardware	Alloc-Fixed	3,386,724	-	2,540,043	846,681
68	6513	Host Computer - Software	Alloc-Fixed	4,306,122	-	3,229,591	1,076,530
69	6514	Networking - Hardware	Total Dir Labor	1,339,360	288,632	693,119	357,609
70	6516	Communications	Total Dir Labor	2,548,799	549,266	1,319,004	680,529
71	6602	Help Desk Support	Total Dir Labor	273,862	59,017	141,723	73,121
72	6615	Host Computer Monitoring	Alloc-Fixed	1,237,463	-	618,731	618,731
73	6616	Desktop Support	Total Dir Labor	381,253	82,160	197,298	101,794
74	6617	System Administration - Unix	Total Dir Labor	751,959	162,047	389,139	200,773
75	6618	System Administration - Windows	Total Dir Labor	810,336	174,627	419,349	216,360
76	6621	Network Support	Total Dir Labor	649,211	139,905	335,967	173,339
77	6622	CIP & Systems Compliance	Total Dir Labor	1,582,650	341,061	819,022	422,568
78	6623	Asset Management	Total Dir Labor	1,103,091	237,716	570,849	294,525
79	6624	Infrastructure Review & Planning	Total Dir Labor	200,605	43,230	103,813	53,562
80	6625	Infrastructure Patch & Vulnerability Mitigation	Total Dir Labor	114,675	24,712	59,344	30,618
81		Total		20,261,110	2,441,788	12,252,056	5,567,267

Exhibit 2
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DRAFT

Line	Activity Code		Allocation	Self-Funding Tariff			
No.	No.	Description	Factor (1)	Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**IT Cyber Security**					
2	6540	Security Compliance and Reporting	Total Dir Labor	2,528,571	544,907	1,308,536	675,128
3	6540A	Controls Assessment	Total Dir Labor	51,776	11,158	26,794	13,824
4	6540B	Virus/Malware Reporting and Response	Total Dir Labor	1,035,482	223,146	535,862	276,474
5	6540D	Intrusion Monitoring and Response	Total Dir Labor	339,284	73,116	175,579	90,589
6	6540E	System Compliance Enhancement	Total Dir Labor	63,565	13,698	32,895	16,972
7	6541	Security SW Tools Program	Total Dir Labor	127,318	27,437	65,887	33,994
8	6543	Critical Infrastructure Protection WG (NERC)	Total Dir Labor	27,511	5,929	14,237	7,345
9	6546	IT Audit Support	Total Dir Labor	253,835	54,701	131,360	67,774
10	6548	CIP Compliance & Monitoring	Total Dir Labor	274,499	59,155	142,053	73,291
11		Total		4,701,841	1,013,247	2,433,203	1,255,391
12							
13		**IT Database & Analytics**					
14	6571	DBA Support - MOPS	Total Dir Labor	2,457,123	529,510	1,271,561	656,052
15	6581	IT Bridge Support	Total Dir Labor	46,225	9,962	23,921	12,342
16	6591	Data Architect - MOPS	Total Dir Labor	387,900	83,592	200,738	103,569
17	6594	IT Data Analyst	Total Dir Labor	511,918	110,318	264,918	136,682
18	6595	IT WEB Application Support	Total Dir Labor	601,191	129,557	311,116	160,518
19	6596	IT Data Governance	Total Dir Labor	386,008	83,185	199,759	103,064
20	21706	Enterprise Software Support	Total Dir Labor	1,187,269	255,856	614,412	317,001
21	21801	Software Support - Settlements	Alloc-Fixed	601,194	-	480,955	120,239
22	21802	Software Support - Publishing	Alloc-Fixed	59,274	-	47,419	11,855
23	21803	Software Support - Finance	Alloc-Fixed	450,282	-	360,225	90,056
24	21804	Software Support - Mitigation	Alloc-Fixed	1,040,423	-	832,338	208,085
25	21805	Software Support - TSO	Total Dir Labor	547,866	118,065	283,521	146,280
26	21806	Software Support - Enterprise	Total Dir Labor	417,193	89,905	215,898	111,391
27	21807	Software Support - Planning	Alloc-Fixed	414,663	-	331,731	82,933
28	21808	Training Delivery to NON-IT	Alloc-Fixed	256,173	-	204,939	51,235
29	21809	IT Markets Software Maintenance	Alloc-Fixed	30,817	-	24,653	6,163
30	21811	Single Sign On Support	Alloc-Fixed	106,092	-	84,874	21,218
31	21812	GADS Support	Alloc-Fixed	119,549	-	95,639	23,910
32	21816	CMS Support	Total Dir Labor	167,368	36,068	86,613	44,687
33	21818	Discoverer Support	Total Dir Labor	98,595	21,247	51,023	26,325
34	21819	Ceridian Support	Total Dir Labor	70,728	15,242	36,602	18,884
35	21820	Service Desk Support	Total Dir Labor	47,820	10,305	24,747	12,768
36	21824	FCTS Support	Alloc-Fixed	836,842	-	-	836,842
37	21825	eTariff Support	Alloc-Fixed	47,820	-	38,256	9,564
38	21830	Annual Software Maintenance for Enterpirse Wide Software	Total Dir Labor	186,152	40,116	96,334	49,703
39		Total		11,076,485	1,532,928	6,182,191	3,361,365
40							
41		**IT Energy Management Systems**					
42	21600	Indirect Supervision and Administration	Total Dir Labor	220,258	47,466	113,983	58,809
43	21602	Applications Support	Total Dir Labor	113,638	24,489	58,808	30,341
44	21603	EMS Power System Applications Support	Total Dir Labor	659,381	142,097	341,230	176,055
45	21604	Dispatcher Training Simulatory Support	Alloc-Fixed	2,054,656	1,643,725	410,931	-
46	21605	DAM FTR/ARR Support	Alloc-Fixed	1,760,276	352,055	1,056,166	352,055
47	21606	Real-time Market Support	Alloc-Fixed	2,732,144	546,429	1,639,286	546,429
48	21607	Forecast Support	Alloc-Fixed	323,912	64,782	194,347	64,782
49		Total		7,864,266	2,821,043	3,814,752	1,228,472
50							
51		**IT Enterprise Applications Development**					
52	6518	Employee Development - Software	Total Dir Labor	32,139	6,926	16,632	8,581
53	21701	IT Settlement Application Support	Alloc-Fixed	12,856	-	10,285	2,571
54	21707	Application Analysis and Conceptual Design	Alloc-Fixed	187,424	-	149,939	37,485
55	21708	Application Design Evaluation and Selection	Alloc-Fixed	656,782	-	525,426	131,356
56	21709	Technology Evaluation and Selection	Alloc-Fixed	719,927	-	575,942	143,985
57	21710	Indirect Supervision and Administration	Alloc-Fixed	748,700	-	598,960	149,740
58	21711	EWR and CAPA Analysis	Alloc-Fixed	142,210	-	113,768	28,442
59		Total		2,500,039	6,926	1,990,952	502,161
60							
61		**IT Power System Modeling Management**					
62	21650	Indirect Supervision and Administration	Total Dir Labor	146,268	31,521	75,694	39,053
63	21651	Power System Modeling	Alloc-Fixed	1,265,192	506,077	506,077	253,038
64	21652	System Application Support	Alloc-Fixed	259,998	103,999	103,999	52,000
65	21654	NX9 Administration	Alloc-Fixed	495,251	198,100	198,100	99,050
66	21655	ICCP Support	Alloc-Fixed	1,119,415	447,766	447,766	223,883
67	21656	Transmission Project Management	Alloc-Fixed	14,450	11,560	2,890	-
68	21657	Model On Demand Admin	Alloc-Fixed	931,887	-	-	931,887
69	21658	Model on Demand Case Requests	Alloc-Fixed	61,387	-	-	61,387
70	21659	Synchrophasor Applications	Alloc-Fixed	86,688	13,003	13,003	60,682
71	21661	MAS Software Dev and Support	Alloc-Fixed	11,021	-	-	11,021
72		Total		4,391,556	1,312,026	1,347,529	1,732,001
73							
74							
75		**Total ISO**		$ 215,070,683	$ 45,082,953	$ 105,115,206	$ 64,872,524

Exhibit 3

Draft 2022 Rate Components (1)

Tariff Schedule (a)	Jan. 1, 2022 (b)
Schedule 1	
Network Load (per kW-hour)	$0.00026
Schedule 2	
TU Bids (Virtual Inc/Dec)	
Submitted	$0.00500
Cleared	$0.06000
FTR Bids	
Submitted	$2.13776
Cleared	$3.87993
TU's	
Block 1 - 1st 12,500	$0.70614
Block 2 - Next 27,000	$0.64195
Block 3 - Over 39,500	$0.57775
Volumetric	
Block 1 - 1st 250,000	$0.39639
Block 2 - Next 1,250,000	$0.36035
Block 3 - Over 1,500,000	$0.32432
Schedule 3	
R-T NCP Load Obligation	$0.24962
Export Rate	$0.53000

(1) From Exh 3, RCL-7, Sch 3.

New England States Committee on Electricity

2022 Budget Presentation

NEPOOL Budget & Finance Subcommittee

August 9, 2021

REVISED October 2021 PC

Change only to p. 12 to reflect actual network load

NESCOE

Background: Budget Review

Term Sheet Provision: "… the annual review of its [NESCOE's] proposed budgets by at least the NEPOOL Participants Committee will be limited to considerations of accounting and reconciliation, so long as spending remains within the boundaries established by those frameworks….. NESCOE will develop an operating budget recommendation for each year in consultation with NEPOOL, the PTO Administrative Committee and ISO-NE within the boundaries of the then-approved five year budget framework …"

- Proposed 2022 budget conforms to:
  - Boundaries of previously reviewed 5-year pro forma (2018 - 2022) supported by NEPOOL in June 2017 & accepted by FERC in August 2017
  - NESCOE commitment not to seek an increase over pro forma budget of more than 10% in any 1 year: 2022 proposed budget is less than 2022 5-year pro forma budget
- Following calendar year 2020, independent auditor concluded NESCOE books conform to generally accepted accounting principles

Background: Policy Priorities

Term Sheet Provision Governing Identification of Policy Priorities:

"Each year NESCOE will produce a ***Report to the New England Governors*** that will document its accomplishments from the preceding year and its projected policy priorities for the coming two years. This report will include a full accounting of spending by NESCOE during the preceding year and proposed budgets for each of the upcoming two years."

Consistent with Term Sheet, 2020 *Report to the New England Governors*:

- ✓ Reviewed work in 2020
- ✓ Projected policy priorities
- ✓ Provided spending from prior year
- ✓ Projected budget information for upcoming two years

Projected Policy Priorities

✓ NESCOE provided to the Governors the ***2020 Annual Report to New England Governors***

✓ Report simultaneously released to NEPOOL & ISO-NE & circulated to the Participants Committee

✓ NESCOE identified forward looking policy priorities at Section V, pages 17

Report in "Resource Center"

www.nescoe.com

Projected Policy Priorities, update

- ✓ Support state officials in furthering the recommendations identified in the "*Advancing the Vision" Report to the New England Governors* in April 2021.
- ✓ Participate actively in ISO-NE's project to remove the Minimum Price Offer Rule from the capacity market design and advocate for consumer cost implications to be chief in the assessment of any associated proposal.
- ✓ Actively engage in FERC's Advance Notice of Proposed Rulemaking on *"Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection"*.
- ✓ Participate in ISO-NE's effort to quantify risks to reliable system operation and to assess potential operational implications of low probability/high impact extreme weather events and to identify a cost-effective approach to any mitigation that may be appropriate.

NESCOE Organization & Misc.

Employees

- Diversity in academic training, skills; blend of private & public sector experience
- Return to employee level of 5 on September 1, 2021 with addition of Sheila Keane to NESCOE staff as Director of Analysis

Office Space

- 4 Bellows Road, Westborough, MA
  - Current lease through November 30, 2021; anticipate renewal
  - Provides small group meeting space needs
- Terminated lease of small room in Portsmouth, New Hampshire

Other Organization Matters

Technical Consultants

Technical consultants assist NESCOE in the regular course of business in analyzing ISO-NE studies and data.

Continue work with technical consultants to conduct independent analysis to inform state officials' decisions on key issues, including, for example:

- ✓ Exeter Associates, Inc.
- ✓ Wilson Energy Economics
- ✓ PeterGFlynn, LLC
- ✓ NewGen
- ✓ Bob Laurita
- ✓ Supplement with other expertise, as needed

Legal Counsel

Litigation is not the primary means by which NESCOE seeks to accomplish its objectives & thus, greater resource and focus has historically, and thus far in 2021, been on technical consulting. Further, while NESCOE produces most legal pleadings and analysis internally, the frequency and type of litigation brought by others influences the extent to which NESCOE engages outside counsel.

- ✓ FERC Counsel: Phyllis G. Kimmel Law Office PLLC

5-Year Pro Forma

Proposed 2022 budget conforms to 2022 budget in 5-year Pro Forma Framework

✓ 2022 Projected Budget in 5-Year Pro Forma:	$2,617,642
✓ 2022 Proposed Budget:	$2,485,156
✓ 2021 Budget, for reference:	$2,428,300

In relation to 2022 5-year Pro Forma, 2022 Proposed Budget reflects:

- ✓ Continued rebalance of technical consulting and legal spending in light of range of proceedings, some of which remain pending
- ✓ Reductions in assumed travel anticipating some continued reliance on remote meeting
- ✓ Reduction in rent (eliminate room in New Hampshire)

5-Year Pro Forma, for reference

NESCOE
PRO FORMA BUDGET 2018-2022*

Expense Category	Year 11 (2018)	Year 12 (2019)	Year 13 (2020)	Year 14 (2021)	Year 15 (2022)
Salaries and Wages					
Salaries	983,020	1,012,510	1,042,886	1,074,172	1,106,397
Payroll Taxes	98,302	101,251	104,289	107,417	110,640
Health and Other Benefits	84,975	87,524	90,150	92,854	95,640
Retirement §401(k)	39,321	40,501	41,716	42,967	44,256
Total, Salaries and Wages	**1,205,618**	**1,241,787**	**1,279,040**	**1,317,411**	**1,356,934**
Direct Expenses - Consulting					
Technical Analysis	517,734	533,266	549,264	565,742	582,714
Legal (FERC)	140,689	144,909	149,257	153,734	158,346
Total, Direct Expenses, Consulting	**658,422**	**678,175**	**698,520**	**719,476**	**741,060**
General and Administrative					
Rent	26,523	27,318	28,138	28,982	29,851
Utilities	5,305	5,464	5,628	5,796	5,970
Office and Administrative Expenses	43,497	44,802	46,146	47,530	48,956
Professional Services	78,126	80,469	82,883	85,370	87,931
Travel/Lodging/Meetings	91,155	93,890	96,706	99,608	102,596
Total General and Administrative	**244,604**	**251,943**	**259,501**	**267,286**	**275,304**
Capital Expendiures & Contingencies					
Computer Equipment	5,665	5,835	6,010	6,190	6,376
Contingencies	211,431	217,774	224,307	231,037	237,968
Capital Expenditures & Contingencies	**217,096**	**223,609**	**230,317**	**237,227**	**244,344**
TOTAL EXPENSES**	**2,325,741**	**2,395,513**	**2,467,379**	**2,541,400**	**2,617,642**

*Based on projected 3% annual adjustment. Line items and categories subject to increase greater than, or decreases from, amounts projected.
Any such changes will be subject to review, input, and recommendations by the NEPOOL Participants Committee (and/or its designees).
**At no time during this 5-year period will NESCOE seek a budget increase of more than 10% in any 1 year or more than 30% on a cumulative basis.

2022 Proposed Budget

NESCOE Pro Forma Budget
Proposed 2022

	2022
Salaries and Wages	
Salaries	1,106,398
Payroll Taxes	110,640
Health and Other Benefits	92,855
Retirement §401(k)	44,256
Total, Salaries and Wages	**1,354,149**
Direct Expenses - Consulting	
Technical Analysis	362,070
Legal (FERC)	362,071
Total, Direct Expenses, Consulting	**724,141**
General and Administrative	
Rent	24,000
Utilities	5,971
Office and Administrative Expenses	47,530
Professional Services	40,000
Travel/Lodging/Meetings	55,000
Total General and Administrative	**172,501**
Capital Expend. & Contingencies	
Computer Equipment	8,442
Contingencies	225,923
Capital Expend. & Contingencies	**234,365**
TOTAL EXPENSES	**2,485,156**
BUDGET	***2,617,642***

2020 & 2021 Spending & Implications for 2022

Unspent funds in any year credited toward future year

2020 Total Spending:	$1,565,585*
2021 Spending to end of June:	$741,049
2021 Projected Year End:	$1,642,659*

* Cumulative prior years' true up, including 2019, was reflected in the 2021 revenue requirement and rates. The 2020 true up will be reflected in the 2022 revenue requirement and rates (see next slide). Any 2021 true up will be reflected in the 2023 revenue requirements and rates.

2022 Projected Billing Rate

With thanks to ISO-NE for calculations

August estimate in ~~strikethrough~~

October PC final in red

2022 Budget: $2,485,156

Less 2020 True Up: ($781,042)

Total Revenue Recovery: $1,704,114

Divided by Total Network Load: ~~217,262,589~~ 231,453,876

(total network load from 2021 ISO-NE tariff; no escalation or reduction used in calculation)

2022 Schedule 5 ~~Estimated~~ Rate ~~$0.00784~~ .00736 per kW-month

Thank you.

Questions?

NESCOE

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Paul Belval, NEPOOL Counsel

DATE: September 30, 2021

RE: Changes to ISO-NE Financial Assurance Policy – Removal of Notarization Requirement

---

At its October 7, 2021 meeting, the Participants Committee will be asked to consider removing the notarization requirement for certain documents to be provided under the ISO New England Financial Assurance Policy ("FAP"). The proposed changes are included in Attachment 1 to this memorandum, and this memorandum summarizes those changes.

Currently, the FAP requires that the following initial and annual certifications by Market Participants and applicants (as applicable) be notarized:

- *Attachment 3* – Minimum Criteria for Market Participation Officer Certification
- *Attachment 4* – Additional Eligibility Requirements Certification
- *Attachment 5* – Certificate Regarding Changes to Submitted Risk Management Policies for FTR Participation

Soon after the start of the COVID pandemic, the FERC issued a temporary order waiving the notarization requirements in FERC tariffs (currently extended through January 1, 2022), so the ISO has not been enforcing those requirements. The ISO now proposes to replace the notarization requirements on those forms with an acknowledgement stating that the signing officer has reviewed the applicable FAP provisions and that the information provided is true, complete and correct. The changes would become effective on January 1, 2022, ensuring that there will be no interim period before the effective date when notarization would be required under the FAP.

The ISO discussed the proposed changes to the FAP with the NEPOOL Budget and Finance Subcommittee (the "Subcommittee") at its August 26 teleconference. During that discussion, the ISO pointed out that notarization only confirms the identity of the signatory and does not address the truthfulness of the statements in the document, meaning that notarization does not hold material value in this context because only the content of the document is used to evaluate credit risk. The ISO also noted that other RTOs do not require notarization on their analogous forms and that eliminating the notarization requirement will result in both cost and time savings for participants and applicants. No one attending the Subcommittee teleconference objected to the FAP changes.

The following form of resolution may be used for Participants Committee action on the FAP changes:

RESOLVED, that the Participants Committee supports the elimination of the notarization requirements under the ISO New England Financial Assurance Policy, as proposed by the ISO and as circulated to this Committee with the September 30, 2021 supplemental notice, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair of the Budget and Finance Subcommittee.

EXHIBIT IA

ISO NEW ENGLAND FINANCIAL ASSURANCE POLICY

Table of Contents

the RNA, be deemed to refer to the group of members as a whole, and any financial assurance provided under the ISO New England Financial Assurance Policy will be credited to the account of the group member with the customer identification at the ISO.

II. MARKET PARTICIPANTS' REVIEW AND CREDIT LIMITS

Solely for purposes of the ISO New England Financial Assurance Policy: a "Municipal Market Participant" is any Market Participant that is either (a) a Publicly Owned Entity except for an electric cooperative or an organization including one or more electric cooperatives as used in Section 1 of the RNA or (b) a municipality, an agency thereof, a body politic or a public corporation (i) that is created under the authority of any state or province that is adjacent to one of the New England states, (ii) that is authorized to own, lease and operate electric generation, transmission or distribution facilities and (iii) that has been approved for treatment as a Municipal Market Participant by the ISO after consultation with the NEPOOL Budget and Finance Subcommittee. Market Participants that are not Municipal Market Participants are referred to as "Non-Municipal Market Participants."

A. Minimum Criteria for Market Participation

Any entity participating or seeking to participate in the New England Markets shall comply with the requirements of this Section II.A. For purposes of this Section II.A, the term "customer" shall refer to both Market Participants and Non-Market Participant Transmission Customers and the word "applicant" shall refer to both applicants for Market Participant status and applicants for transmission service from the ISO.

1. Information Disclosure

(a) Each customer and applicant, on an annual basis (by April 30 each year) shall submit a completed information form in the form of (with only minor, non-material changes) and with the information required by Attachment 6 to the ISO New England Financial Assurance Policy. Customer or applicant shall not be required to disclose information required by Attachment 6 if such disclosure is prohibited by law; provided, however, if the disclosure of any information required by Attachment 6 is prohibited by law, then customer or applicant shall use reasonable efforts to obtain permission to make such disclosure. This information shall be treated as Confidential Information, but its disclosure pursuant to subsection (b) below is expressly permitted in accordance with the a customer) of participation in the New England Markets, then the ISO shall be required to make an informational filing with the Commission as soon as reasonably practicable after taking such action. If the ISO chooses to prohibit (in the case of an applicant) or terminate (in the case of a customer) participation in the New England Markets, then the ISO must file for Commission approval of such action, and the prohibition or termination shall become effective only upon final Commission ruling. No action by the ISO pursuant to this subsection (b) shall limit in any way the ISO's rights or authority under any other provisions of the ISO New England Financial Assurance Policy or the ISO New England Billing Policy.

2. Risk Management

(a) Each customer and applicant shall submit, on an annual basis (by April 30 each year), a certificate in the form of Attachment 3 to the ISO New England Financial Assurance Policy stating that the customer or applicant has: (i) either established or contracted for risk management procedures that are applicable to participation in the New England Markets; and (ii) has established or contracted for appropriate training of relevant personnel that is applicable to its participation in the New England Markets. The certificate must be signed on behalf of the customer or applicant by a Senior Officer of the customer or applicant~~ and must be notarized~~. An applicant that fails to provide this certificate will be prohibited from participating in the New England Markets until the deficiency is rectified. If a customer fails to provide this certificate by end of business on April 30, then the ISO shall issue a notice of such failure to the customer on the next Business Day and, if the customer does not provide the certificate to the ISO within 5 Business Days after issuance of such notice, then the customer will be suspended as described in Section III.B.3 of the ISO New England Financial Assurance Policy until the deficiency is rectified.

(b) Each applicant prior to commencing activity in the FTR market shall submit to the ISO or its designee the written risk management policies, procedures, and controls, including, if requested by the ISO in its sole discretion, supporting documentation (which may include an organizational chart (or portion thereof) or equivalent information) that demonstrates the segregation of duties within such risk policies, procedures, and controls of the such deficiencies within 55 days after issuance of such notice. (If April 30 falls within that 55 day window, the ISO may choose not to require a separate submission on April 30 as described in subsection (b) above.) If an applicant's revised written policies, procedures, and controls do not adequately address the deficiencies identified in the notice, then the applicant will be prohibited from participating in the New England Markets. If a customer's revised written policies, procedures, and controls do not adequately address the deficiencies identified in the notice, then the customer will be suspended (as described in Section III.B of the ISO New England Financial Assurance Policy).

3. Communications

Each customer and applicant shall submit, on an annual basis (by April 30 each year), a certificate in the form of Attachment 3 to the ISO New England Financial Assurance Policy stating that the customer or applicant has either established or contracted to establish procedures to effectively communicate with and respond to the ISO with respect to matters relating to the ISO New England Financial Assurance Policy and the ISO New England Billing Policy. Such procedures must ensure, at a minimum, that at least one person with the ability and authority to address matters related to the ISO New England Financial Assurance Policy and the ISO New England Billing Policy on behalf of the customer or applicant, including the ability and authority to respond to requests for information and to arrange for additional financial assurance as necessary, is available from 9:00 a.m. to 5:00 p.m. Eastern Time on Business Days. Such procedures must also ensure that the ISO is kept informed about the current contact information (including phone numbers and e-mail addresses) for the person or people described above. The certificate must be signed on behalf of the customer or applicant by a Senior Officer of the customer or applicant~~ and must be notarized~~. An applicant that fails to provide this certificate will be prohibited from participating in the New England Markets until the deficiency is rectified. If a customer fails to provide this certificate by end of business on April 30, then the ISO shall issue a notice of such failure to the customer on the next Business Day and, if the customer does not provide the certificate to the ISO within 5 Business Days after issuance of such notice, then the customer will be suspended as described in Section III.B.3 of the ISO New England Financial Assurance Policy until the deficiency is rectified.

(i) Where a customer or applicant fails to meet the capitalization requirements, the customer or applicant will be required to provide an additional amount of financial assurance in one of the forms described in Section X of the ISO New England Financial Assurance Policy in an amount equal to 25 percent of the customer's or applicant's total financial assurance requirement (excluding FTR Financial Assurance Requirements).

(ii) An applicant that fails to provide the full amount of additional financial assurance required as described in subsection (i) above will be prohibited from participating in the New England Markets until the deficiency is rectified. For a customer, failure to provide the full amount of additional financial assurance required as described in subsection (i) above will have the same effect and will trigger the same consequences as exceeding the "100 Percent Test" as described in Section III.B.2.c of the ISO New England Financial Assurance Policy.

(iii) Any additional financial assurance provided pursuant to this Section II.A.4(c) shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy.

5. Additional Eligibility Requirements

All customers and applicants shall at all times be:

(a) An "appropriate person," as defined in sections 4(c)(3)(A) through (J) of the Commodity Exchange Act (7 U.S.C. § 1 *et seq.*);

(b) An "eligible contract participant," as defined in section 1a(18)(A) of the Commodity Exchange Act and in 17 CFR § 1.3(m); or

(c) A "person who actively participates in the generation, transmission, or distribution of electric energy," as defined in the Final Order of the Commodity Futures Trading Commission published at 78 FR 19880 (April 2, 2013).

Each customer must demonstrate compliance with the requirements of this Section II.A.5 by submitting to the ISO on or before September 15, 2013 a certificate in the form of Attachment 4 to the ISO New England Financial Assurance Policy that (i) certifies that the customer is now and in good faith will seek to remain in compliance with the requirements of this Section II.A.5 and (ii) further certifies that if it no longer satisfies these requirements it shall immediately notify the ISO in writing and shall immediately cease all participation in the New England Markets. If the customer is relying on section 4(c)(3)(F) of the Commodity Exchange Act, it shall accompany the certification with supporting documentation reasonably acceptable to the ISO, provided that letters of credit shall be in the form of Attachment 2 to the ISO New England Financial Assurance Policy and shall be in an amount equal to the difference between five million dollars and the customer's total assets. Any such supporting documentation shall serve to establish eligibility under this Section II.A.5 and shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy. The certificate must be signed on behalf of the customer by a Senior Officer of the customer~~ and must be notarized~~. A customer that fails to provide this certificate by September 15, 2013 shall be immediately suspended and the ISO shall initiate termination proceedings against the customer.

Each applicant must submit with its membership application a certificate in the form of Attachment 4 to the ISO New England Financial Assurance Policy that (i) certifies that the applicant is now and in good faith will seek to remain in compliance with the requirements of this Section II.A.5 and (ii) further certifies that if it no longer satisfies these requirements it shall immediately notify the ISO in writing and shall immediately cease all participation in the New England Markets. If the applicant is relying on section 4(c)(3)(F) of the Commodity Exchange Act, it shall accompany the certification with supporting documentation reasonably acceptable to the ISO, provided that letters of credit shall be in the form of Attachment 2 to the ISO New England Financial Assurance Policy and shall be in an amount equal to the difference between five million dollars and the applicant's total assets. Any such supporting documentation shall serve to establish eligibility under this Section II.A.5 and shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy. The certificate must be signed on behalf of the applicant by a Senior Officer of the applicant~~ and must be notarized~~.

The ISO, at its sole discretion, may require any applicant or customer to submit to the ISO documentation in support of the certification provided pursuant to this Section

ATTACHMENT 3

ISO NEW ENGLAND MINIMUM CRITERIA FOR MARKET PARTICIPATION OFFICER CERTIFICATION FORM

Certifying Entity:	

I,____, a duly authorized Senior Officer of ____("Certifying Entity"), understanding that ISO New England Inc. is relying on this certification as evidence that Certifying Entity meets the minimum criteria for market participation requirements set forth in Sections II.A.2 and II.A.3 of the ISO New England Financial Assurance Policy (Exhibit IA to Section I of the ISO New England Transmission, Markets and Services Tariff) (the "Policy"), hereby certify that I have full authority to bind Certifying Entity and further certify as follows:

1. Certifying Entity has established or contracted for written policies, procedures, and controls applicable to participation in the New England Markets, approved by Certifying Entity's independent risk management function[1], which provide an appropriate, comprehensive risk management framework that, at a minimum, clearly identifies and documents the range of risks to which Certifying Entity is exposed, including, but not limited to, credit risk, liquidity risk, concentration risk, default risk, operation risk, and market risk.

2. Certifying Entity has established or contracted for appropriate training of relevant personnel that is applicable to its participation in the New England Markets.

3. Certifying Entity has appropriate operating procedures and technical abilities to promptly and effectively respond to all ISO New England communications and directions.

I acknowledge that I have read and understand the provisions of the Policy, including those provisions describing ISO New England's minimum criteria for market participation requirements and the remedies available to ISO New England in the event of a customer or applicant not satisfying those requirements. I acknowledge that the information provided herein true, complete, and correct and is not misleading or incomplete for any reason, including by reason of omission.

Date: ________________________________ ____
(Signature)

Print Name:________________________________

Title: ____________________________________

[1] As used in this certification, a Certifying Entity's "risk management function" can include appropriate corporate persons or bodies that are independent of the Certifying Entity's trading functions, such as a risk management committee, a risk officer, a Certifying Entity's board or board committee, or a board or committee of the Certifying Entity's parent company.

~~Subscribed and sworn before me___________________________________, a notary public of the State of ______________________________, in and for the County of________________________, this _______ day of________________________, 20_______.~~

~~(Notary Public Signature)~~

~~My commission expires:_____/_____/_____~~

ATTACHMENT 4

ISO NEW ENGLAND ADDITIONAL ELIGIBILITY REQUIREMENTS
CERTIFICATION FORM

Certifying Entity:	

I,____, a duly authorized Senior Officer of ____(“Certifying Entity”), understanding that ISO New England Inc. is relying on this certification as evidence that Certifying Entity meets the additional eligibility requirements set forth in Section II.A.5 of the ISO New England Financial Assurance Policy (Exhibit IA to Section I of the ISO New England Inc. Transmission, Markets and Services Tariff) (the “Policy”), hereby certify that I have full authority to bind Certifying Entity and further certify as follows:

1. Certifying Entity is now and in good faith will seek to remain (check applicable box(es)):

   ☐ an “appropriate person,” as defined in section(s) [   ] of the Commodity Exchange Act (7 U.S.C. § 1 *et seq*.) (specify which section(s) of Commodity Exchange Act sections 4(c)(3)(A) through (J) apply)) (if Certifying Entity is relying on section 4(c)(3)(F), it shall accompany this certification with supporting documentation reasonably acceptable to the ISO, provided that letters of credit shall be in the form of Attachment 2 to the ISO New England Financial Assurance Policy and shall be in an amount equal to the difference between five million dollars and the Certifying Entity’s total assets. Any such supporting documentation shall serve to establish eligibility under this Section II.A.5 and shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy);

   ☐ an “eligible contract participant,” as defined in section 1a(18)(A) of the Commodity Exchange Act and in 17 CFR § 1.3(m); or

   ☐ a “person who actively participates in the generation, transmission, or distribution of electric energy,” as defined in the Final Order of the Commodity Futures Trading Commission published at 78 FR 19880 (April 2, 2013).

2. If at any time Certifying Entity no longer satisfies the criteria in paragraph 1 above, Certifying Entity will immediately notify ISO New England in writing and will immediately cease all participation in the New England Markets.

I acknowledge that I have read and understand the provisions of the Policy, including those provisions describing ISO New England’s additional eligibility requirements and the remedies available to ISO New England in the event of a customer or applicant not satisfying those requirements. I acknowledge that the information provided herein true, complete, and correct and is not misleading or incomplete for any reason, including by reason of omission.

____
(Signature)

Print Name:______________________________

Title: __________________________________

Date: __________________________________

~~Subscribed and sworn before me______________________________, a notary public of the State of ______________________________, in and for the County of________________________, this ________ day of________________________, 20________.~~

____

~~(Notary Public Signature)~~

~~My commission expires:______/______/______~~

ATTACHMENT 5

ISO NEW ENGLAND CERTIFICATE REGARDING CHANGES TO SUBMITTED RISK MANAGEMENT POLICIES FOR FTR PARTICIPATION

Certifying Entity:	

I,____, a duly authorized Senior Officer of ____(“Certifying Entity”), understanding that ISO New England Inc. is relying on this certification as evidence that Certifying Entity meets the annual certification requirement for FTR market participation regarding its risk management policies, procedures, and controls set forth in Section II.A.2(b) of the ISO New England Financial Assurance Policy (Exhibit IA to Section I of the ISO New England Inc. Transmission, Markets and Services Tariff) (the “Policy”), hereby certify that I have full authority to bind Certifying Entity and further certify as follows (check applicable box):

1. ☐ There have been no changes to the previously submitted written risk management policies, procedures, and controls (and any supporting documentation, if applicable) applicable to the Certifying Entity’s participation in the FTR market.

   OR

2. ☐ There have been changes to the previously submitted written risk management policies, procedures, and controls (and any supporting documentation, if applicable) applicable to the Certifying Entity’s participation in the FTR market and such changes are clearly identified and attached hereto.*

I acknowledge that I have read and understand the provisions of the Policy, including those provisions describing ISO New England’s risk management policy requirements for FTR market participants and the remedies available to ISO New England in the event of a customer or applicant not satisfying those requirements. I acknowledge that the information provided herein true, complete, and correct and is not misleading or incomplete for any reason, including by reason of omission.

____
(Signature)

Print Name:___________________________________

Title: ____

Date: ____

~~Subscribed and sworn before me___________________________________, a notary public of the State of ______________________________, in and for the County of_________________________, this _______~~

~~day of_________________________, 20_______.~~

____

~~(Notary Public Signature)~~

~~My commission expires:_____/_____/_____~~

____

* As used in this certificate, "clearly identified" changes may include a redline comparing the current written risk management policies, procedures, and controls and the previously submitted written risk management policies, procedures, and controls; or resubmission of the written risk management policies, procedures, and controls with a bulleted list of all changes, including section and/or page numbers.

M E M O R A N D U M

TO: NEPOOL Participants Committee

FROM: Eric Runge, NEPOOL Counsel

DATE: September 29, 2021

RE: OATT Attachment K Revisions for Resource Assumptions

At the October 7, 2021 meeting of the Participants Committee you will be asked to vote on revisions to Section II, Attachment K, of the ISO-NE Tariff regarding certain resource assumptions used in planning ("Resource Assumption Revisions"). ISO-NE has proposed the Resource Assumption Revisions to allow ISO-NE to expand the resources that can be relied on to address system concerns to include all existing resources, and to provide clarification on the current language. The proposed Resource Assumption Revisions are further described in the materials from ISO-NE included with this cover memo.

The Transmission Committee considered the Resource Assumption Revisions over the course of three meetings. At its September 28 meeting the Transmission Committee unanimously recommended Participants Committee support for the proposal. This item would have been on the Consent Agenda but for the timing of the meetings.

The following resolution can be used for Participants Committee action:

> *Resolved*, that the Participants Committee supports the Resource Assumption Revisions as recommended by the Transmission Committee and as distributed to the Participants Committee for its October 7, 2021 meeting, together with [any changes agreed to at the meeting, and]any non-substantive changes agreed to be by the Chair and Vice-Chair of the Transmission Committee after the meeting.

ISO new england

memo

To: NEPOOL Transmission Committee

From: Brent Oberlin, Director, Transmission Planning

Date: September 22, 2021

Subject: Attachment K Revisions: Resource Assumptions

The ISO is requesting a vote on the Attachment K Revisions: Resource Assumptions proposal. This proposal will allow the ISO to expand the resources that can be relied on to address system concerns, and to provide clarification on the current language. Many resources and being operated independently of any obligation to do so, yet Attachment K doesn't allow the ISO to utilize these generators in the Needs Assessment studies or Public Policy and Transmission Studies. This proposal remedies that, and will help ensure that system needs identified in subsequent solutions development recognize existing resources and do not inadvertently overbuild in the absence of that recognition.

The specific proposal for the committee's consideration at its September 28th meeting has been presented in the meeting dates outlined below.

- July 14, 2021, agenda item #5 https://www.iso-ne.com/event-details?eventId=144201
- August 24, 2021, agenda item #4 https://www.iso-ne.com/event-details?eventId=144086
- September 28, agenda item #4 https://www.iso-ne.com/event-details?eventId=144088

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

Attachment K, Section 4.1:

(f) Treatment of Market Responses in Needs Assessments

The ISO shall reflect proposed market responses in the regional system planning process. Market responses may include, but are not limited to, resources (e.g., demand-side projects and distributed generation), and Elective Transmission Upgrades.

In performing Needs Assessments, the ISO shall rely on certain resources to prevent the identification of system needs. Specifically, the ISO shall incorporate or update information regarding future resources, with the exception of imports across external tie lines, in Needs Assessments that have been proposed and (i) have cleared in a Forward Capacity Auction pursuant to Market Rule 1 of the ISO Tariff, (ii) have been selected in, and are contractually bound by, a state-sponsored ~~Request~~ request ~~For~~ for ~~Proposals~~proposals, ~~or~~ (iii) have a financially binding obligation pursuant to a contract, or (iv) have been forecast in the ISO's Forecast Report of Capacity, Energy, Loads and Transmission. The ISO shall also incorporate or update information regarding all existing resources, with the exception of imports across external tie lines, in Needs Assessments. Imports across future or existing external tie lines will not be relied upon unless such imports (i) have a Capacity Supply Obligation corresponding to the year of study (ii) have been selected in, and are contractually bound by, a state-sponsored request for proposals, (iii) have a financially binding obligation pursuant to a contract, or (iv) may be represented by a minimum flow based on HQ Interconnection Capability Credits. The ISO will model out-of-service all submitted Retirement De-List Bids, submitted Permanent De-List Bids, and demand bids that have cleared in a substitution auction, and may model out-of-service rejected-for-reliability Static De-List Bids and rejected-for-reliability Dynamic De-List Bids from the most recent Forward Capacity Auction. With respect to having been selected in, and being contractually bound by a state-sponsored request for proposals, or having a financially binding obligation pursuant to a contract~~(ii) or (iii) above~~, demonstration of such contracts is accomplished through submittal for ISO review of an order or other similar authorization from the appropriate state regulatory agency, along with a copy of the contract, that together demonstrate the contractual requirements. These documents may be submitted by: the Project Sponsor; the state regulatory agency authorizing the contract; a transmission company that is a counterparty to the contract; or by a third-party organization representing the interests of the New England states regarding energy related issues, such as NESCOE. The ISO shall incorporate or update information regarding a proposed Elective Transmission Upgrade in a Needs Assessment at a time after the studies corresponding to the Elective Transmission Upgrade are completed (including receipt of approval under Section I.3.9 of the Tariff), a commercial operation date has been ascertained, and for which the certification has been accepted in accordance with Section III.12 of the Tariff. In the case where the Elective Transmission Upgrades are proposed in conjunction with the interconnection of a resource, these Elective Transmission Upgrades shall be considered at the same time as the proposed resource is considered in the Needs Assessment provided that the studies corresponding to the Elective Transmission Upgrade are completed (including receipt of approval under Section I.3.9 of the Tariff), a commercial operation date has been ascertained, and for which the certification has been accepted in accordance with Section III.12 of the Tariff.

Attachment K, Section 4A.3:

(b) Treatment of Market Solutions in Public Policy Transmission Studies

The ISO shall reflect proposed market responses in the Public Policy Transmission Study. Market responses may include, but are not limited to, resources (e.g., demand-side projects and distributed generation), Merchant Transmission Facilities and Elective Transmission Upgrades.

In performing Public Policy Transmission Studies, the ISO shall rely on certain resources to prevent the identification of transmission needs driven by Public Policy Requirements. Specifically, the ISO shall incorporate in the Public Policy Transmission Study information regarding future resources, with the exception of imports across external tie lines, that have been proposed and (i) have cleared in a Forward Capacity Auction pursuant to Market Rule 1 of the ISO Tariff, (ii) have been selected in, and are contractually bound by, a state-sponsored ~~Request~~ request ~~For~~ for ~~Proposals~~proposals, or (iii) have a financially binding obligation pursuant to a contract, or (iv) have been forecast in the ISO's Forecast Report of Capacity, Energy, Loads and Transmission. The ISO shall also incorporate or update information regarding all existing resources, with the exception of imports across external tie lines, in Public Policy Transmission Studies. Imports across future or existing external tie lines will not be relied upon unless such imports (i) have been selected in, and are contractually bound by, a state-sponsored request for proposals, (ii) have a financially binding obligation pursuant to a contract, or (iii) are represented by a minimum flow based on HQ Interconnection Capability Credits. . The ISO will model out-of-service all submitted Retirement De-List Bids, submitted Permanent De-List Bids, and demand bids that have cleared in a substitution auction, and may model out-of-service rejected-for-reliability Static De-List Bids and rejected-for-reliability Dynamic De-List Bids from the most recent Forward Capacity Auction. With respect to having been selected in, and being contractually bound by a state-sponsored request for proposals, or having a financially binding obligation pursuant to a contract~~(ii) or (iii) above~~, demonstration of such contracts is accomplished through submittal for ISO review of an order or other similar authorization from the appropriate state regulatory agency, along with a copy of the contract, that together demonstrate the contractual requirements. These documents may be submitted by: the Project Sponsor; the state regulatory agency authorizing the contract; a transmission company that is a counterparty to the contract; or by a third-party organization representing the interests of the New England states regarding energy related issues, such as NESCOE. The ISO shall incorporate information regarding a proposed Merchant Transmission Facility or Elective Transmission Upgrade in a Needs Assessment at a time after the studies corresponding to the Merchant

Transmission Facility or Elective Transmission Upgrade are completed (including receipt of approval under Section I.3.9 of the Tariff), and a commercial operation date has been ascertained, with the exception of Elective Transmission Upgrades that are proposed in conjunction with the interconnection of a resource, which shall be considered at the same time as the proposed resource is considered in the Public Policy Transmission Study.

SEPTEMBER 28, 2021 | TRANSMISSION COMMITTEE| WEBEX

Attachment K Revisions: Resource Assumptions

Third Presentation

Brent Oberlin

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Project Title: Attachment K Resource Assumptions

Proposed Effective Date: January 2022

- Attachment K of the OATT limits resources that can be relied upon in Needs Assessments (NA) and Public Policy Transmission Studies (PPTS) to those that have an obligation through the Forward Capacity Market, are contractually bound by a state RFP, or have a financially binding obligation pursuant to a contract
- Many resources are being operated independently of any obligation to do so, yet Attachment K doesn't allow the ISO to utilize these generators to address system concerns in NA and PPTS
- Changes to Attachment K are being considered to allow the ISO to expand the resources that can be relied on to address system concerns, and to provide clarification to the current language
- This is the third meeting at the Transmission Committee to discuss these changes, which are anticipated to be filed with FERC later this year

Problem Statement

- The system is undergoing changes in the generation mix, causing the need to review the Attachment K provisions on resources that can be relied on to address system concerns in NA and PPTS
- The current language in Attachment K does not allow the ISO to rely on certain resources in NA or PPTS which are operational
  - This may cause the identification of system needs and subsequent solution development for issues that can be addressed by recognizing existing resources
- Some clarification to the current language in Attachment K will also be beneficial

SUMMARY OF PROPOSED CHANGES

Changes to the Current Rules

- Existing Resources*
  - The ISO is proposing to revise Attachment K so that **all existing** resources can be relied on in NA and PPTS
  - This includes those that do not meet the criteria in the current language found in Attachment K Section 4.1(f) and 4.A.3(b)
  - Current Attachment K language related to de-list bids will remain
    - The specific language in Attachment K is as follows: "The ISO will model out-of-service all submitted Retirement De-List Bids, submitted Permanent De-List Bids, and demand bids that have cleared in a substitution auction, and may model out-of-service rejected-for-reliability Static De-List Bids and rejected-for-reliability Dynamic De-List Bids from the most recent Forward Capacity Auction."
- Future Resources*
  - No changes are being proposed to the handling of future resources that can be relied on in NA and PPTS

* Does not include imports across external tie lines. These are addressed separately, later in the presentation.

Clarifications to the Current Rules

- While changes are being made to Attachment K, the ISO would like to clarify the language to specifically call out forecasted resources that are contained in the CELT
- While the term "resources" in Attachment K has included imports across external tie lines, this should be explicitly stated and further clarification is needed

FEEDBACK DELIVERED DURING THE AUGUST TRANSMISSION COMMITTEE MEETING

Responses to Stakeholder Feedback

- At the August meeting, the ISO stated that the changes to Attachment K would not change outage scheduling requirements for resources, but wanted to confirm. This information has been verified to be correct

Changes since the August TC meeting

- During the August TC meeting, the ISO responded to stakeholder questions
- Those questions were taken into consideration but did not result in changes to the draft Tariff revisions in Attachment K that were provided in August

Conclusion

- The ISO is proposing that all existing resources be relied upon in Needs Assessments and PPTS, taking advantage of known resources to potentially reduce the need for additional transmission infrastructure
- The ISO is also seeking to clarify the handling of imports and forecasted resources
- There have been no changes since the August TC

Stakeholder Schedule for Attachment K

Proposed Effective Date – Mid-December 2021

Stakeholder Committee and Date	Scheduled Project Milestone
July 14, 2021	Discussion of concepts, introduction to Attachment K revisions and review of proposed redlines
August 24, 2021	Respond to stakeholder questions from previous meeting and continued review of proposed redlines
September 28, 2021	Vote on the proposed Attachment K revisions
Participants Committee October 7, 2021	Vote

Questions

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APPENDIX A

Current Attachment K Language

Current Attachment K language, Section 4.1(f) and 4A.3(b)

- “Specifically, the ISO shall incorporate or update information regarding resources in Needs Assessments that have been proposed and (i) have cleared in a Forward Capacity Auction pursuant to Market Rule 1 of the ISO Tariff, (ii) have been selected in, and are contractually bound by, a state-sponsored Request For Proposals, or (iii) have a financially binding obligation pursuant to a contract. The ISO will model out-of-service all submitted Retirement De-List Bids, submitted Permanent De-List Bids, and demand bids that have cleared in a substitution auction, and may model out-of-service rejected-for-reliability Static De-List Bids and rejected-for-reliability Dynamic De-List Bids from the most recent Forward Capacity Auction.”

APPENDIX B

Red-lined Attachment K Language

Proposed Tariff Changes: Attachment K

Tariff Section	Tariff Change	Reason for Change
Attachment K, Section 4.1(f)	In performing Needs Assessments, the ISO shall rely on certain resources to prevent the identification of system needs. Specifically, the ISO shall incorporate or update information regarding future resources, with the exception of imports across external tie lines, in Needs Assessments that have been proposed and (i) have cleared in a Forward Capacity Auction pursuant to Market Rule 1 of the ISO Tariff, (ii) have been selected in, and are contractually bound by, a state-sponsored ~~Request~~ request ~~For~~ for ~~Proposals~~proposals, ~~or~~ (iii) have a financially binding obligation pursuant to a contract, or (iv) have been forecast in the ISO's Forecast Report of Capacity, Energy, Loads and Transmission. The ISO shall also incorporate or update information regarding all existing resources, with the exception of imports across external tie lines, in Needs Assessments. Imports across future or existing external tie lines will not be relied upon unless such imports (i) have a Capacity Supply Obligation corresponding to the year of study (ii) have been selected in, and are contractually bound by, a state-sponsored request for proposals, (iii) have a financially binding obligation pursuant to a contract, or (iv) may be represented by a minimum flow based on HQ Interconnection Capability Credits. The ISO will model out-of-service all submitted Retirement De-List Bids, submitted Permanent De-List Bids, and demand bids that have cleared in a substitution auction, and may model out-of-service rejected-for-reliability Static De-List Bids and rejected-for-reliability Dynamic De-List Bids from the most recent Forward Capacity Auction. With respect to having been selected in, and being contractually bound by a state-sponsored request for proposals, or having a financially binding obligation pursuant to a contract~~(ii) or (iii) above~~, demonstration of such contracts is accomplished through submittal for ISO review of an order or other similar authorization from the appropriate state regulatory agency, along with a copy of the contract, that	Allow existing resources to be relied on in NA and PPTS; clarify the handling of imports; clarify the inclusion of resources in the CELT

M E M O R A N D U M

TO: NEPOOL Participants Committee

FROM: Eric Runge, NEPOOL Counsel

DATE: September 29, 2021

RE: **NEPOOL Initial Comments on:** FERC Advance Notice of Proposed Rulemaking regarding "Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection"

On July 15, 2021 the Federal Energy Regulatory Commission (the "Commission") issued an Advance Notice of Proposed Rulemaking in Docket No. RM21-17-000 on "Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection" (the "ANOPR").[1] The Commission opened this rulemaking proceeding pursuant to its authority under Section 206 of the Federal Power Act ("FPA") to consider the potential need for reforms to improve the electric regional transmission planning and cost allocation and generator interconnection processes. The initial comment deadline remains **October 12, 2021**, despite requests for extension of time to December 1, 2021.[2]

Given the Commission's decision to not extend the initial comment deadline, at the request of the Transmission Committee Vice-Chair, NEPOOL counsel prepared a set of initial comments ("NEPOOL Initial Comments") for review and input by the NEPOOL officers. A copy of the draft NEPOOL Initial Comments reflecting your officers' comments and input has been included with the materials for the Participants Committee's October 7 meeting. The NEPOOL Initial Comments describe past and current New England activities that NEPOOL is engaged in that are relevant to the ANOPR topics.

The NEPOOL Initial Comments do not take any new positions, but instead make the following points: (1) the Commission should **provide regional flexibility** in compliance with any final rule; (2) the Commission should **respect existing stakeholder processes**, such as the NEPOOL process; (3) the Commission should **allow adequate time to respond to any final rule**; and (4) New England has experienced and is experiencing some of the issues identified in the ANOPR regarding integration of renewables.

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[1] The ANOPR, together with a NEPOOL counsel memo and presentation related to it can be accessed with the materials for the August 24, 2021 and the September 28, 2021 meetings of the NEPOOL Transmission Committee here: https://www.iso-ne.com/committees/transmission/transmission-committee/.

[2] In an order issued on September 3, the Commission denied the requests to extend the initial comment deadline past October 12 but did extend the reply comment deadline from November 9 to November 30.

The NEPOOL Initial Comments, with the input and preliminary sign-off by the NEPOOL officers, was reviewed with the Transmission Committee at its September 28 meeting and no objections were raised. One minor edit was suggested and made.

The NEPOOL Initial Comments discuss actions and positions that have already been approved by NEPOOL and do not take new substantive positions; therefore, officer review and sign-off on the Comments is sufficient and no NEPOOL vote is required unless requested by a Participant. If a vote is requested, the following resolution can be used to vote on this item:

> *Resolved*, that the Participants Committee approves the NEPOOL Initial Comments on the ANOPR, as distributed to the committee for its October 7, 2021 meeting, together with any changes agreed to at the meeting, and any non-substantive changes agreed to be by the Chair and Vice-Chair of the Transmission Committee after the meeting.

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Building for the Future Through	)	
Electric Regional Transmission Planning	)	
and Cost Allocation and	)	RM21-17-000
Generator Interconnection	)	

INITIAL COMMENTS OF THE
NEW ENGLAND POWER POOL PARTICIPANTS COMMITTEE
(October 12, 2021)

Pursuant to the Federal Energy Regulatory Commission's ("Commission") Advance Notice of Proposed Rulemaking issued on July 15, 2021 in the above-captioned proceeding,[1] the signatories to the New England Power Pool Agreement ("NEPOOL"), acting through the Participants Committee,[2] hereby submits these Comments.[3] NEPOOL is the principal stakeholder organization in the New England Regional Transmission Organization ("RTO")

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[1] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 176 FERC ¶ 61,024 at P 183 (2021) ("ANOPR").

[2] Capitalized terms not defined herein have the meanings ascribed thereto in the Second Restated NEPOOL Agreement, Participants Agreement, or the ISO New England Inc. ("ISO-NE") Transmission, Markets and Services Tariff ("ISO-NE Tariff" or the "Tariff").

[3] The New England Power Pool Agreement was initially entered into in 1971 and the number of signatories to that agreement as it has evolved over time has grown to include over 500 members. Those signatories are referred to both as "members" and "Participants" and they are referred to collectively as "NEPOOL." The Participants include all of the electric utilities rendering or receiving services under the ISO-NE Tariff, as well as independent power generators, marketers, load aggregators, brokers, consumer-owned utility systems, demand response providers, developers, end users and a merchant transmission provider. Pursuant to revised governance provisions accepted by the Commission in *ISO New England Inc. et al.*, 109 FERC ¶ 61,147 (2004), the Participants act through the NEPOOL Participants Committee. The NEPOOL Participants Committee is authorized by Section 6.1 of the Second Restated NEPOOL Agreement and Section 8.1.3(c) of the Participants Agreement to represent NEPOOL in proceedings before the Commission. NEPOOL is the principal stakeholder organization for the New England Regional Transmission Organization ("RTO").

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through a Commission-approved contractual association with ISO New England Inc. ("ISO-NE" or the "ISO").[4]

Prior to the formation of the New England RTO in 2005, and since 1997, the NEPOOL Participants Committee held the Federal Power Act ("FPA") Section 205 filing rights for the regional Open Access Transmission Tariff ("OATT"). Both before and since the RTO formation NEPOOL has been and continues to be actively involved in the primary subject matter of the ANOPR: namely, transmission planning, cost allocation and generator interconnection. Further, NEPOOL is actively involved in the design and development of the competitive wholesale ISO-NE markets. NEPOOL's members include all of the sectors of those markets in New England, including, as particularly relevant to the ANOPR, transmission owners, developers of new renewable generation and interconnection customers of all kinds. Since the 1996 restructuring of the NEPOOL arrangements and the establishment of the ISO in 1997, NEPOOL has been committed to a markets-based approach to meet system needs[5], to the extent practicable.

NEPOOL submits these initial Comments to: (i) provide some New England background on the subject matter of the ANOPR and current relevant activities in which NEPOOL and its

[4] The Participants Agreement is the Commission-approved contract between NEPOOL and ISO-NE that sets forth the stakeholder processes for all changes to the ISO-NE Tariff and related rules and procedures. The Participants Agreement is a fundamental element of the RTO arrangements for New England. Through the Participants Agreement, NEPOOL is assured the opportunity for meaningful and timely stakeholder input and vote on virtually all changes sought to FERC jurisdictional transmission or market services as the principal stakeholder organization in the New England RTO. The Participants Agreement can be found here: https://www.iso-ne.com/static-assets/documents/2015/10/parts_agree.pdf

[5] A markets-based approach to system needs allows markets to determine what supply resources will come forward to meet system needs and where they will be located, as opposed to an integrated resource planning approach. Additionally, under a markets-based approach, market solutions to transmission system needs, such as generation built at particular locations, take priority and can displace transmission solutions to meet those same needs, where practicable.

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members are participating: (ii) request that the Commission allow for regional variations and flexibility in the development and implementation of any final rule(s) that might come out of this proceeding; (iii) request that the Commission allow for adequate time to respond to any final rule that calls for fundamental changes, particularly given existing priorities and stakeholder processes for such changes; and (iv) urge the Commission to respect the existing RTO arrangements for stakeholder processes in the regions, particularly those processes that have been established and used successfully in New England through the Participants Agreement.

NEPOOL has not yet developed an organizational position on many of the substantive concepts and exploratory proposals that are presented in the ANOPR, but plans to provide its input on that substance as both the NEPOOL positions and the Commission's substantive proposals are further developed and defined in the rulemaking process.

I. BACKGROUND

NEPOOL has a long history of working among its members in the various industry sectors[6] to proactively address regional system planning, cost allocation and interconnection matters. In so doing, NEPOOL has worked with others, including ISO-NE, the Participating Transmission Owners Administrative Committee ("PTO AC") and the six New England States, acting individually and collectively through both the New England States Committee on

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[6] All sectors of the wholesale electric industry in New England are represented in the six sectors of NEPOOL's governance structure, including: Transmission, Generation, Suppliers, Publicly Owned Entities, Alternative Resources, and End Users. NEPOOL's governance provisions allocate voting shares equally among these sectors. NEPOOL positions are established through votes of the Participants Committee, typically based on recommendations from the principal NEPOOL Technical Committees (Markets, Committee, Reliability Committee and Transmission Committee), which also vote to establish recommendations. Most votes in NEPOOL require a minimum two-thirds vote to pass, with the exception of votes on changes to the Market Rules, which have a sixty percent threshold to pass.

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Electricity ("NESCOE") and the New England Conference of Public Utilities Commissioners, to effectively address these subjects.[7]

Past Activities:

The summary below provides a few of the more relevant examples of NEPOOL proactively addressing transmission planning, cost allocation and interconnection matters, and briefly describes some of those major efforts:

- *Regional System Planning:* In 2000 ISO-NE filed a comprehensive regional system planning proposal, developed with NEPOOL input, seven years before the issuance of Order No. 890, based on processes already underway in New England. The Commission accepted this proposal and the related tariff revisions,[8] and ISO-NE began issuing Regional System Plans ("RSPs") in 2002. The RSP process became the basis for planning major transmission infrastructure upgrades in New England to address reliability issues, and relieve transmission constraints on the system, thereby enabling new generation to reach load and eliminating or greatly reducing expensive congestion on the system. A fundamental premise of transmission planning in New England under the planning provisions of the ISO-NE Tariff is that market solutions (e.g., generation or storage assets) to system needs are preferred and that transmission solutions are planned and built only when market solutions do not address identified needs. To date, NEPOOL has consistently supported this markets-focused approach to planning over other approaches, such as integrated resource planning.

- *Transmission Cost Allocation:* In 2003 NEPOOL, and ISO-NE filed a comprehensive transmission cost allocation proposal (supported by the PTO AC) with clear rules for the allocation of costs for regional transmission facilities identified as needed for reliability or market efficiency. The Commission accepted this proposal and the related Tariff revisions, which have been the basis for approximately $12 billion dollars of transmission investment and cost allocation in the region since 2004.[9]

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[7] The PTO AC, as the administrative committee representing the Participating Transmission Owners, and NESCOE, as the regional state committee, are both fundamental organizations to the RTO arrangements for New England, along with NEPOOL and ISO-NE.

[8] *See ISO New England Inc.*, 91 FERC ¶ 61,311 at 62,076-77 (2000). *See also, ISO New England Inc. and New England Power Pool*, 95 FERC ¶ 61,384 (2001) (authorizing ISO-NE to oversee regional transmission planning); *ISO New England Inc.*, *et al.*, 106 FERC ¶ 61,280 (2004) (approving ISO-NE's regional system planning process in the context of the Commission's approval of ISO-NE's RTO status subject to fulfillment of requirements and establishing hearing and settlement judge procedures).

[9] *See New England Power Pool and ISO New England Inc.*, 105 FERC ¶ 61,300 (2003).

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- *Coordinating/Co-optimizing Interconnection Processes and Forward Capacity Market*: In 2008 ISO-NE, NEPOOL and the PTO AC jointly filed a proposal and related Tariff revisions to effect a closer alignment and co-optimization of the interconnection process and the Commission-approved Forward Capacity Market ("FCM"), including a "first-cleared, first-served" approach for capacity resources. The Commission accepted this proposal and the related Tariff revisions.[10] Under this approach, the allocation of interconnection capacity service and the associated obligations are based on the results of the FCM. This approach provides a mechanism to discipline multiple capacity Interconnection Requests when they are pending in the interconnection queue – the first cleared resource moves forward and the remaining resources decide whether to participate in a subsequent auction or withdraw.

- *Clustering Interconnection Projects Needing Common Transmission Infrastructure:* In 2017 ISO-NE, NEPOOL and the PTO AC jointly filed an interconnection clustering proposal to address interconnection queue backlogs, primarily resulting from the influx of proposed renewable clean energy projects seeking to interconnect from focused locations in New England. The Commission accepted this proposal and the related Tariff revisions.[11] Those provisions have now been used twice: first, to address a backlog of approximately 6,000 MW of onshore wind projects located in Western and Northern Maine behind a constrained transmission interface to load centers in Southern New England; and, second, to seek to address the interconnection of several thousand MW of offshore wind generation currently being developed in federal waters off the coast of Massachusetts and Rhode Island seeking to interconnect in the transmission constrained area of Cape Cod.

Current Activities:

NEPOOL also is actively engaged now with ISO-NE, representatives of all six New England states, and other stakeholders on several studies and processes that are directly relevant to the subject matter of the ANOPR. The summary below describes some of those major efforts:

- *NEPOOL Future Grid Reliability Study* ("FGRS"): In 2020 and early 2021 NEPOOL developed a proposal for a study of the future grid (circa 2040) and its anticipated reliability needs.[12] A main purpose of the FGRS is to identify gaps in markets or

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[10] *See ISO New England Inc. and New England Power Pool*, 126 FERC ¶ 61,080 (2009).

[11] *ISO New England Inc.*, 161 FERC ¶ 61,123 (2017).

[12] Concurrently, NEPOOL is evaluating potential market design pathways to further decarbonization of the New England energy supply mix through ISO-NE administered clean energy procurement markets or carbon pricing markets.

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infrastructure and then to work through how to address those gaps in the collaborative New England stakeholder process. The FGRS will examine what changes are needed to enable New England's power system to reliably operate in 2040 while meeting current New England States' energy and environmental policies. The FGRS assumes that the requirements in existing clean energy and environmental laws in the six New England States will be met, resulting in major changes to the resource mix and load. The FGRS is proceeding in two phases, with Phase I currently under way as an Economic Study under ISO-NE's Order No. 890 Attachment K process, and Phase II to be further developed in 2022. Phase I is focusing on multiple long-range (2040) scenarios and analyzing them through production cost simulation, ancillary services simulation, a resource adequacy screen, and probabilistic resource availability analysis. Phase II is expected to focus on particular scenarios of interest and analyze them through revenue sufficiency and select system security analyses and any other analyses NEPOOL deems appropriate at the time of commencing Phase II.

- *2050 Transmission Study*: At the request of the New England States, ISO-NE has begun a transmission study to inform the States and all stakeholders of the amount and type of transmission infrastructure needed to cost-effectively integrate large-scale clean energy resources and distributed energy resources ("DERs") across the region. More specifically, the States have requested the following (as quoted below from the New England States Vision Statement[13]):

    1. Initiate a regional transmission planning effort that provides a high-level transmission system plan to meet the needs of States' energy transition, with participation and input by State officials,
    2. Use the scenarios that have been developed and used in various States' analyses of pathways to decarbonization as a starting point for developing multiple future resource scenarios (e.g., 3-4) as the basis for assessing future regional transmission needs, and conduct a conceptual regional transmission system plan for the select future scenarios for identified timeframes (e.g., 2030, 2040 and 2050),
    3. Provide needed transmission system planning information to the region, including high-level cost estimates,
    4. From the conceptual system plan, conduct detailed analyses for specific scenarios, with the objective being to understand future conditions and needs, including: (1) Onshore system upgrades, including specific areas that need strengthening, (2) Offshore systems that may be needed to support offshore wind resources, (3) Potential options that should be explored, including non-transmission alternatives, and (4) The impact of DERs (both distributed generation and flexible load sources) on transmission needs,

[13] See New England States Vision Statement here: https://nescoe.com/resource-center/vision-stmt-oct2020/

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5. With the insights gained from the scenarios used in the long-term system planning, conduct stakeholder meetings to discuss the potential use of transmission to integrate all of the necessary energy resources in the region at the lowest cost possible, and
6. Informed by States' direction, conduct detailed planning processes to maximize the use of existing transmission, build new transmission only where absolutely necessary, and use competitive processes to minimize costs to consumers.

Currently, the NEPOOL Transmission Committee is considering an ISO-NE Tariff revision that would help implement part of what the New England States are seeking in this proposal by authorizing ISO-NE to engage in longer-range (out to 2050), scenario based planning studies.[14]

- *Clean Energy Transition Study*: Transmission Planning for the Clean Energy Transition is an ISO-NE transmission planning study to analyze operational issues and constraints that may arise on a future grid with significantly greater amounts of distributed energy resources, a greater amount of renewables, and different operational characteristics than today's grid.[15] The study was prompted by trends in New England that the ISO anticipates will accelerate in the future, including shifting demand, rapid deployment of distributed energy resources and large-scale renewable clean energy development, and increased energy imports from neighboring systems. This study is currently being discussed and refined at the ISO-NE Planning Advisory Committee with input from NEPOOL Participants and other interested stakeholders.

II. COMMENTS

A. In any final rule that comes out of this rulemaking proceeding the Commission should *allow for regional variations and flexibility in compliance* for RTO/ISO regions, such as New England.

To the extent the Commission is considering generic rule changes that might be applied across the country, NEPOOL urges that the Commission fully consider and account for differences across the many regions of the country. Each region of the country has different

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[14] See July 14, 2021 ISO-NE presentation to Transmission Committee, Slide 6, here: https://www.iso-ne.com/static-assets/documents/2021/07/a05_tc_2021_07_14_overview.pdf

[15] See recent ISO-NE presentation on the Clean Energy Transition Study here: https://www.iso-ne.com/static-assets/documents/2021/08/a3_transmission_planning_for_the_clean_energy_transition_pilot_study_results_and_assumption_changes.pdf

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factors that apply in the transmission planning, cost allocation and interconnection contexts, including such factors as: existing rules and processes for these subjects, market design differences, various stakeholder processes and RTO arrangements, whether the regions are made up of multiple or single states, different requirements from the states affecting wholesale markets, resource mix and transmission, and other important factors that call for regional variations.

In the New England region, ISO-NE and NEPOOL have a long history of working together proactively to identify reliability, transmission or market needs and developing appropriate solutions to them. As described above, this history includes proactive initiatives to develop solutions such as: (i) a regional system planning process in 2000; (ii) a comprehensive transmission cost allocation method in 2003; (iii) an integration of the Forward Capacity Market with the interconnection rules in 2008; and (iv) an interconnection clustering methodology in 2017 to remove bottlenecks in the ISO-NE interconnection queue and advance the integration of large-scale renewable generation on the system. Often those solutions have features that are specifically tailored to work best for the bulk electric system or wholesale market design that is already in place, or to account for other unique features of the six-state New England regional system.

The Commission should allow ISO-NE, NEPOOL, the PTOs and the New England States to continue to have the flexibility to develop solutions in planning, cost allocation and generator interconnection that work best for New England, consistent with both past practice and Commission policy and precedent. As a multi-state region that has functioned effectively as a centrally dispatched, tight power pool for more than fifty years, New England's challenges in these areas may be quite different than challenges faced by other regions, and New England

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solutions are best tailored to the specific facts and circumstances in New England rather than through generic directives to the industry. This point is especially applicable to market-based solutions, which need to work together with other market design features that are unique to the region.

B. Any changes to stakeholder processes coming out of this rulemaking should *respect existing stakeholder RTO arrangements*, such as the Participants Agreement and NEPOOL stakeholder processes for New England.

The ANOPR emphasizes the desirability and importance of transmission planning processes that are transparent and consider the needs and views of all interested entities.[16] New England recognized the advantages transparent regional planning processes and, beginning in 2000 and then more formally in the formation of the New England RTO in 2004-2005 established the Planning Advisory Committee ("PAC"). The PAC meets at least monthly and is open to all interested persons, including representatives from the States, market participants, and any other interested persons (subject in some cases to meeting Critical Energy Infrastructure Information clearance requirements). In addition, the RTO arrangements provide NEPOOL a contractual right to review, discuss, provide input and take advisory votes on all proposed changes to the Tariff, including those related to transmission planning, regional transmission cost allocation and interconnection to the ISO-NE administered transmission system.

Under the Participants Agreement, ISO-NE must bring any proposed changes to the ISO-NE Tariff and its related rules and procedures to NEPOOL for consideration and vote. Similarly,

[16] E.g., ANOPR at PP 52, 60.

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the PTOs are required under the RTO arrangements to bring certain regional transmission rate-related proposals to NEPOOL for consideration and vote.[17]

The NEPOOL Participants develop, own and operate the assets or facilities, or represent the buyers and sellers and customers, that will be directly impacted by any ISO-NE rule changes. They often have the most expertise about, and experience with, the subject matter, and can provide the most informed commercial insight into the feasibility and consequences of a proposed rule change. Fully engaging the Participants before completing and filing proposed changes helps assure that they have a chance to fully understand proposed changes, and an opportunity to suggest and explore alternatives. It also helps ensure that the ISO fully understands how the proposal will impact Participants and the ISO-NE markets, and provides the opportunity to resolve or narrow any issues.

Typically, the stakeholder processes under the Participants Agreement for considering transmission-related changes to the ISO-NE Tariff and related rules produce outcomes that are broadly supported by ISO-NE, NEPOOL, the PTO AC and the New England States. When they do not produce consensus on changes to those arrangements, they more precisely define areas of disagreement. In some instances NEPOOL Participants make alternative proposals that, if supported by NEPOOL, are filed with the Commission as an alternative to the ISO's proposal.[18]

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[17] The Participating Transmission Owners and ISO-NE are parties to the Transmission Operating Agreement ("TOA"). Section 3.04 sets forth certain legal rights and obligations of the parties with respect to tariff changes, and Section 3.04(l) obligates the PTOs to observe certain stakeholder processes for regional rate filings.

[18] To the extent these alternative changes relate to market rules rather than transmission provisions of the ISO-NE Tariff, Section 11.1.5 of the Participants Agreement provides for a "jump ball" pursuant to which NEPOOL-supported changes are to be submitted on equal footing with ISO-NE proposals, with both proposals to be considered as alternative Section 205 filings under the Federal Power Act.

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Such processes provide the Commission far better and more complete information to ensure that rates, terms and conditions of jurisdictional service in New England are just and reasonable.

The NEPOOL stakeholder process is essential to obtain the full set of stakeholder perspectives, a prerequisite to yield the solutions that work best for New England. This full set of perspectives includes those of ISO-NE, the NEPOOL Participants, the PTOs, and the New England States.[19] Thus, NEPOOL has a special stakeholder advisory role in the context of proposed tariff changes in the New England RTO, while the PAC provides an opportunity for all voices to be heard regarding regional system planning related matters.

NEPOOL urges that any rule that comes out of this rulemaking process should respect existing stakeholder processes and avoid compromising the Commission-approved New England regional system planning process and the proven NEPOOL stakeholder process.

C. The Commission should *allow adequate time* for ISO-NE and NEPOOL to work together on solutions that work best for New England.

The ANOPR is silent on how quickly the Commission might act on the issues and potential reforms it has identified. NEPOOL urges that any such Commission reforms provide sufficient time to ensure that changes can be worked out fully in the existing RTO stakeholder processes. As noted above, ISO-NE, NEPOOL and other stakeholders are currently engaged in several regional studies that could suggest changes to the rules and processes for system planning. For example, the Future Grid Reliability Study is intended to identify, among other things, gaps that will need to be closed to maintain a reliable future grid.

[19] The New England States participate in NEPOOL meetings through NESCOE as well as through individual participation by representatives for the New England States that elect to participate directly.

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In the past, when New England has identified needs for change in the areas of regional system planning, transmission cost allocation and generator and transmission interconnection, NEPOOL, ISO-NE, the PTO AC and the New England States have worked collaboratively and proactively to develop and implement proposals to address those needs. This collaborative approach to change often takes more time than a top-down forced approach but it can yield better results with less subsequent complications in the long run. Some of the proposed changes in the ANOPR would fundamentally change New England's current structures and market-focused approaches and shift them to more of an integrated resource planning approach. The Commission should allow sufficient time for regions, such as New England, to assess the implications of such changes and develop proposals that work for the region in the context of current structures and processes and applicable state policies driving the future grid transformation.

D. NEPOOL has observed and is experiencing in New England some of the issues identified in the ANOPR regarding the integration of renewables.

Section IV.A of the ANOPR is focused largely on planning for the integration of renewable energy resources into the grid. This topic has been a focus of New England for several years. While NEPOOL does not have an organizational position on a solution for transmission infrastructure to integrate these resources, it notes that to date these projects are driven by state policies and procurements, and that the States have the ability to procure transmission that would enable the desired clean energy to reach its intended customers through an ISO-NE Tariff mechanism currently in place, Elective Transmission Upgrades ("ETU"). For

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example, currently the State of Maine is exploring such a procurement and the use of the ETU mechanism.[20]

The New England grid is undergoing a major transformation, largely driven by State energy and environmental policies, coupled with technology developments and decreasing costs of solar and wind energy generation. Solar generation has been mostly in the form of distributed energy resources interconnecting to the distribution system though utility scale development has been increasing recently. Thus far transmission upgrade needs for solar generation have been identified only in limited circumstances, while sub-transmission and distribution system upgrades have been identified more often.

For wind generation, NEPOOL has observed two major influxes of such projects in the interconnection queue at focused locations in New England. Beginning especially around 2015/2016 in anticipation of state renewable energy procurements, large amounts of onshore wind entered the ISO-NE interconnection queue, with proposed points of interconnection in Northern and Western Maine, two favorable areas for onshore wind from a land and wind perspective. While some of these onshore wind projects have been interconnected, others have remained in the study queue for an extended period of time or been withdrawn from it because of: (i) backlogs in the queue (which have been partly addressed through the clustering revisions to the ISO-NE Tariff), or (ii) the need for expensive, major upgrades to the transmission system

[20] *See e.g.,* ME H. 123 *An Act Pertaining to Transmission Lines Not Needed for Reliability or Local Generation* (2021); ME H. 1494 *An Act to Establish Requirements for the Construction of Elective Transmission Lines by Transmission and Distribution Utilities* (2020). Massachusetts legislators have also introduced bills in recent years to allow for such procurement. *See e.g.,* S.2477-1, Proposed Amendment on Planned Transmission (2019); S.2092-13, Proposed Amendment on Energy Sector Compliance with the Global Warming Solutions Act (2016); H.4377-12 Proposed Amendment on Transmission Solicitation (2016).

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to remove constraints that otherwise limit this energy from flowing to load centers in Southern New England.

Similarly, and more recently, NEPOOL is observing the influx of thousands of megawatts of offshore wind projects in federal waters off the coast of Southern New England.[21] These projects often seek to come ashore with the maximum amount of capacity that can be included in a single interconnection request (1,200 MW). Several of these projects currently seeking to interconnect on Cape Cod have triggered the ISO-NE clustering interconnection process, which has led to studies showing the need for major new transmission infrastructure to allow interconnection on Cape Cod and for the energy to flow from there to the rest of the region.[22]

NEPOOL and its individual members are and will remain actively engaged with ISO-NE, the Commission, the New England States and other stakeholders in the region to consider appropriate paths forward for the further integration of renewable clean energy resources and the planning of related transmission infrastructure.

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[21] See ISO-NE June 14, 2021 presentation to the Interregional Planning Stakeholder Advisory Committee here: https://www.iso-ne.com/static-assets/documents/2021/06/a04_2_2021-06-04_ipsac_iso-ne_osw_development_update_final.pdf.

[22] See *Id.* at Slide 10.

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III. CONCLUSION

WHEREFORE, for the reasons set forth above, NEPOOL respectfully requests that the Commission take these NEPOOL Initial Comments into consideration in its future rulemaking decisions in this proceeding.

Respectfully submitted,

NEPOOL Participants Committee

By: *_/s/ Eric Runge____________*

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Dated: October 12, 2021

Its Attorneys

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Pat Gerity, NEPOOL Counsel

DATE: September 30, 2021

RE: Membership Subcommittee Recommendation Regarding Associate Non-Voting Participant (ANVP) Proposal

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You will be asked at the October 7 meeting to consider limited amendments to the Second Restated NEPOOL Agreement (RNA) to replace the definition of, and reference to, Fuels Industry Participant with "Associate Non-Voting Participant" (the Amendments), as well as certain related actions to reflect and implement those Amendments. This memorandum briefly summarizes the background and substance of the Subcommittee's recommendations and includes forms of resolution for Participants Committee action. Included with this memorandum is a draft 134th Agreement to reflect the Amendments and a copy of the Subcommittee's September 10 Notice of Actions.

The Amendments are proposed to address a suggestion, raised most recently at the June 3, 2021 meeting when NEPGA was determined to be a Fuels Industry Participant, that some further consideration be given to the description and arrangements for this category in light of the evolution of the kinds of Participants determined to be and participating as Fuels Industry Participants.[1]

Following consideration of the Fuels Industry Participant arrangements over the course of three Subcommittee meetings, there was general agreement that no change be made to the non-Sector, non-voting status to which such Participants are subject, nor to the fees for such participation.[2] However, there was agreement that the name for this category of Participant be changed, with "Associate Non-Voting Participant" identified to distinguish and better characterize the group of gas industry participants and energy sector trade associations that have become Participants under these arrangements. The Subcommittee also agreed to a simplified definition of this category of Participant. Finally, to support the simplified definition, the Subcommittee agreed to recommend that each of the current Fuels Industry Participants be determined to be Associate Non-Voting Participants and that the Subcommittee be delegated authority to approve for membership, subject to the Standard Membership Conditions, Waivers

[1] Current Fuels Industry Participants are:

gas industry participants	*energy sector trade associations*
Algonquin Gas Transmission	Advanced Energy Economy (AEE)
Excelerate Energy	American Petroleum Institute (API)
Repsol Energy North America	New England Power Generators Assoc. (NEPGA)

[2] Associate Non-Voting Participants will receive notice of, materials for, and be permitted to attend as Participants, any Principal Committee meeting. Application and annual fees for the status will continue to be $5,000. No additional contributions to Participant Expenses nor any additional financial assurance will be required.

and Reminders (SCWRs), Entities that are gas industry participants (as currently defined in the RNA) and energy sector trade associations (like AEE, API and NEPGA). The additional delegation with respect to energy sector trade associations (the Subcommittee has had the authority for gas industry participants based on definition that has been included in the RNA) is consistent with the NPC approvals of the AEE, API and NEPGA, does not impact the eligibility of End User Organizations, and will avoid the requirement for future NPC action each time an application is received from an energy sector trade association. Other Entities that do not meet the definition of either gas industry participant or energy sector trade association could be determined to be a Non-Voting Associate Member, but the responsibility for that determination would remain with the Participants Committee unless or until later delegated.

Accordingly, the following forms of resolution, either voted separately or together if that is the will of the Committee, could be used to act on the Subcommittee's recommendations:

> RESOLVED, that the Participants Committee authorizes and directs the Balloting Agent (as defined in the Second Restated NEPOOL Agreement) to circulate ballots for the approval of changes to the Second Restated NEPOOL Agreement (that replace the definition of, and reference to, Fuels Industry Participant with "Associate Non-Voting Participant") (the Amendments), but with such non-material changes therein as the Chair of the Membership Subcommittee may approve, to each Participant for execution by its voting member or alternate on this Committee or such Participant's duly authorized officer.
>
> RESOLVED, that, subject to Participants Committee approval in balloting and FERC acceptance of the Amendments, each of the following are determined as permitted by those amendments to be a "Associate Non-Voting Participant": Algonquin Gas Transmission, Excelerate Energy, Repsol Energy North America, Advanced Energy Economy, American Petroleum Institute, and The New England Power Generators Association.
>
> RESOLVED, that the Participants Committee, pursuant to Sections 8.1.3(f) and (g) of the Participants Agreement, hereby delegates to the Membership Subcommittee the authority to approve an applicant to be an Associate Non-Voting Participant, subject to acceptance of the Standard Conditions, Waivers and Reminders, if the Subcommittee determines that the applicant is either:

(i) a ***gas industry participant*** (i.e. an Entity that meets all four of the following criteria: (a) the Participant is engaged in the production, gathering, processing, marketing, or transmission of natural gas for sale at wholesale or retail in one or more of the New England states; and (b) the Participant does not participate directly in the New England Markets; and (c) the Participant is not eligible to join or designate a voting member of a Sector (other than the End User Sector); and (d) the Participant elects to be a treated as an Associate Non-Voting Participant before its membership application is approved by NEPOOL); or

(ii) an ***energy sector trade association*** (i.e. an organization of Entities engaging in the storage, production, supply, transportation, or distribution of energy, organized to promote and improve business conditions in the energy sector and not to engage in a regular business of a kind ordinarily carried on for profit, and no part of the net earnings of which inures to the benefit of any of its members).

If you have any questions ahead of the October 7 meeting, please contact me at pmgerity@daypitney.com or (860) 275-0533.

ONE HUNDRED THIRTY-FOURTH AGREEMENT AMENDING NEW ENGLAND POWER POOL AGREEMENT (Associate Non-Voting Participant)

THIS ONE HUNDRED THIRTY-FOURTH AGREEMENT AMENDING NEW ENGLAND POWER POOL AGREEMENT, dated as of October 7, 2021 ("134th Agreement"), amends the New England Power Pool Agreement (the "NEPOOL Agreement").

WHEREAS, effective February 1, 2005 the NEPOOL Agreement was amended by the One Hundred Seventh Agreement Amending New England Power Pool Agreement and restated as the Second Restated NEPOOL Agreement, and has subsequently been amended numerous times; and

WHEREAS, the Participants desire to amend further the Second Restated NEPOOL Agreement to reflect the revisions detailed herein.

NOW, THEREFORE, upon approval of this 134th Agreement by the NEPOOL Participants Committee in accordance with the procedures set forth in the Second Restated NEPOOL Agreement, the Participants agree as follows:

SECTION 1 AMENDMENTS

1.1 Addition of Definition. The following definition is added to Section 1 of the Second Restated NEPOOL Agreement and inserted in the appropriate alphabetical order:

> Associate Non-Voting Participant is a Participant that is determined by the Participants Committee or its designee to be an Associate Non-Voting Participant. Notwithstanding any other provision of this Agreement, an Associate Non-Voting Participant shall not have the right to join, or be or vote as a member of, a Sector. An Associate Non-Voting Participant, which is not a Related Person of another Participant, shall have the right however, to appoint to each Principal Committee a non-voting member, and an alternate to that member. Such a non-voting member and alternate shall have all of the rights of any other member of a Principal Committee except the right to vote or to serve as an officer of a Principal Committee.

1.2 Deletion of Definition. The definition of Fuels Industry Participant is deleted from Section 1 of the Second Restated NEPOOL Agreement in its entirety.

1.3 Amendment to Section 6.2. The first sentence of the last paragraph of Section 6.2 is amended to read as follows:

> All Participants (other than Data-Only Participants, Associate Non-Voting Participants, GIS-Only Participants, and Provisional Members) have the right to join and be a member of a Sector.

SECTION 2
MISCELLANEOUS

2.1 This 134th Agreement shall become effective January 1, 2022, or on such other date as the Commission shall provide that the amendment reflected herein shall become effective.

2.2 Capitalized terms used in this 134th Agreement that are not defined herein shall have the meanings ascribed to them in the Second Restated NEPOOL Agreement.

~~1.28~~1.9A ~~Fuels Industry~~Associate Non-Voting Participant is a Participant that ~~either (i) meets all four of the following criteria: (a) the Participant is engaged in the production, gathering, processing, marketing, or transmission of natural gas for sale at wholesale or retail in one or more of the New England states; and (b) the Participant does not participate directly in the New England Markets; and (c) the Participant is not eligible to join or designate a voting member of a Sector (other than the End User Sector); and (d) the Participant elects to be a treated as a Fuels Industry Participant before its membership application is approved by NEPOOL; or (ii)~~ is determined by the Participants Committee ~~to be a Fuels Industry~~or its designee to be an Associate Non-Voting Participant. Notwithstanding any other provision of this Agreement, ~~a Fuels Industry~~an Associate Non-Voting Participant shall not have the right to join, or be or vote as a member of, a Sector. ~~A Fuels Industry~~ An Associate Non-Voting Participant, which is not a Related Person of another Participant, shall have the right however, to appoint to each Principal Committee a non-voting member, and an alternate to that member. Such a non-voting member and alternate shall have all of the rights of any other member of a Principal Committee except the right to vote or to serve as an officer of a Principal Committee.

NEPOOL
NEW ENGLAND POWER POOL

TO: NEPOOL Participants Committee Members and Alternates

FROM: NEPOOL Membership Subcommittee

DATE: September 10, 2021

SUBJECT: **ACTIONS OF THE NEPOOL MEMBERSHIP SUBCOMMITTEE**

This memorandum is notification that the NEPOOL Membership Subcommittee took the following actions at its meeting today:

1. **New Member Applications Approved.** Approved the application for membership in NEPOOL of each of the following Entities, subject to the following routine conditions: (i) that the applicant sign and return the Standard Membership Conditions, Waivers and Reminders acceptance letter; (ii) that the ISO and NEPOOL Counsel find the application complete; and (iii) that the applicant execute an Indemnification Agreement (requested effective date in parentheses):

   - J.P. Morgan Ventures Energy Corp. (Oct 1, 2021) Supplier Sector
   - Granite Apollo, LLC (Oct 1, 2021) AR Sector, RG Sub-Sector, Large Group Member
   - Oxford Energy Center, LLC (Oct 1, 2021) Provisional Member

2. **Recommendation Regarding Associate Non-Voting Participant (ANVP) Proposal.** The Subcommittee recommended that the Participants Committee approve the ANVP proposal by (i) approving for balloting an agreement to amend the Second Restated NEPOOL Agreement to replace the definition of Fuels Industry Participant with a definition for Associate Non-Voting Participant; (ii) approving a resolution that, to effect an orderly transition, determines that each existing Fuels Industry Participant is an Associate Non-Voting Participant; and (iii) delegating to the Membership Subcommittee the determination that a gas industry participant or an energy sector trade association is an Associate Non-Voting Participant (retaining for itself such determination for Entities that are not either a gas industry participant or an energy sector trade association as defined in the ANVP Proposal). A copy of the ANVP proposal is attached to this notice of actions.

   The Participants Committee (NPC) will be asked to take action on this recommendation at the October 7, 2021 NPC meeting. Additional information and background material will be circulated with the materials for that meeting.

Next ***regularly***-scheduled Subcommittee meeting: ***Tuesday***, ***October 12, 2021 10:00 a.m***

Subcommittee Activity since Jan 1, 2021

Number of Meetings	New Member Applications	Terminations	Other Actions
11	27	16	2 • (NEPGA recommendation) • (Associate Non-Voting Participant Proposal recommendation)

2021 NEPOOL Membership Totals (as of September 10, 2021)

New Members	Terminations					Gen	TO	Supplier	POE	AR	End User	Other
28	16	Total Members		522		66	20	216	62	88	45	25
		Voting Members		288		12	5	136	59	24	38	14

Membership Subcommittee-Recommended ANVP Proposal (2021.09.10)

A. Delete definition of Fuels Industry Participant[1] and replace with the following definition of "Associate Non-Voting Participant":

1.9A Associate Non-Voting Participant is a Participant that is determined by the Participants Committee or its designee to be an Associate Non-Voting Participant. Notwithstanding any other provision of this Agreement, an Associate Non-Voting Participant shall not have the right to join, or be or vote as a member of, a Sector. An Associate Non-Voting Participant, which is not a Related Person of another Participant, shall have the right however, to appoint to each Principal Committee a non-voting member, and an alternate to that member. Such a non-voting member and alternate shall have all of the rights of any other member of a Principal Committee except the right to vote or to serve as an officer of a Principal Committee.

B. Participants Committee resolutions to be approved concurrently with the balloting of the Agreement to approve the changes in A. above:

1. Determination that each Fuels Industry Participant[2] is an Associate Non-Voting Participant.

2. Delegation of Authority to the Membership Subcommittee to determine an Applicant to be an Associate Non-Voting Participant if it is either:

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[1] 1.28A Fuels Industry Participant is a Participant that either (i) meets all four of the following criteria: (a) the Participant is engaged in the production, gathering, processing, marketing, or transmission of natural gas for sale at wholesale or retail in one or more of the New England states; and (b) the Participant does not participate directly in the New England Markets; and (c) the Participant is not eligible to join or designate a voting member of a Sector (other than the End User Sector); and (d) the Participant elects to be a treated as a Fuels Industry Participant before its membership application is approved by NEPOOL; or (ii) is determined by the Participants Committee to be a Fuels Industry Participant. Notwithstanding any other provision of this Agreement, a Fuels Industry Participant shall not have the right to join, or be or vote as a member of, a Sector. A Fuels Industry Participant, which is not a Related Person of another Participant, shall have the right however, to appoint to each Principal Committee a nonvoting member, and an alternate to that member. Such a non-voting member and alternate shall have all of the rights of any other member of a Principal Committee except the right to vote or to serve as an officer of a Principal Committee.

2 Current Fuels Industry Participants are:

gas industry participants	*energy sector trade associations*
Algonquin Gas Transmission	Advanced Energy Economy (AEE)
Excelerate Energy	American Petroleum Institute (API)
Repsol Energy North America	NEPGA

(i) a ***gas industry participant*** (i.e. an Entity that meets all four of the following criteria: (a) the Participant is engaged in the production, gathering, processing, marketing, or transmission of natural gas for sale at wholesale or retail in one or more of the New England states; and (b) the Participant does not participate directly in the New England Markets; and (c) the Participant is not eligible to join or designate a voting member of a Sector (other than the End User Sector); and (d) the Participant elects to be a treated as an Associate Non-Voting Participant before its membership application is approved by NEPOOL); or

(ii) an ***energy sector trade association*** (i.e. an organization of Entities engaging in the storage, production, supply, transportation, or distribution of energy, organized to promote and improve business conditions in the energy sector and not to engage in a regular business of a kind ordinarily carried on for profit, and no part of the net earnings of which inures to the benefit of any of its members).

Applicants not meeting these definitions must, absent later delegation to the Membership Subcommittee, be determined by the Participants Committee to be an Associate Non-Voting Participant.

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of October 5, 2021

The following activity, as more fully described in the attached litigation report, has occurred since the report dated August 31, 2021 ("last Report") was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

COVID-19

No Activity to Report

I. Complaints/Section 206 Proceedings

*	2	206 Investigation: ISO-NE Tariff Schedule 25 and Section I.3.10 (EL21-94)	Sep 7	FERC institutes investigation; ISO-NE response due on or before ***Nov 8, 2021***
			Sep 8	FERC issues notice of proceeding & Oct 30, 2020 refund effective date
			Sep 8-Sep 30	NEPOOL, NESCOE, Brookfield, Calpine, Dominion, Eversource, HQ US, LS Power, MA AG, MMWEC, National Grid, NECEC Transmission, NEPGA, NextEra, NRG, CT DEEP, MA DOER, ACPA, EPSA, RENEW, Public Citizen intervene
	3	Green Development DAF Charges Complaint Against National Grid (EL21-47)	Sep 23	FERC denies in part, and grants in part, Complaint. National Grid not permitted, unless and until it complies with the requirement for a separate agreement, to assess DAF charges to Narragansett in association with the upgrades necessary for the Projects
	3	NEPGA Net CONE Complaint (EL21-26)	Sep 23	FERC issues an *Allegheny Order*, modifying the discussion in, but sustaining the results of, the *May 28 Orders*
	4	NECEC/Avangrid Complaint Against NextEra/Seabrook (EL21-6)	Sep 7	FERC issues an order establishing additional briefing in this proceeding; initial briefs due on or before ***Oct 7, 2021***; reply briefs, ***Oct 22, 2021***.

II. Rate, ICR, FCA, Cost Recovery Filings

	8	VTransco Request to Defer 2021/22 Retiree Lump Sum Payment Cost Recovery (ER21-2627)	Sep 22	FERC authorizes VTransco to defer retiree costs, eff. Dec 31, 2021
	8	CSC CIP IROL Cost Recovery: Pre-Jun 1, 2021 Regulatory Asset Cost Recovery (ER21-2334)	Sep 30	CSC requests rehearing of the *August 31 Order* denying CSC's pre-Jun 1, 2021 CIP IROL cost recovery plan
	9	Mystic 8/9 Cost of Service Agreement (ER18-1639)	Sep 13	FERC issues a "Notice of Denial of Rehearing by Operation of Law and Providing for Further Consideration" of the requests for rehearing of the *Mystic ROE Order*
			Sep 15	Mystic submits 2021 Capital Expenditures Informational Filing

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

*	11	eTariff § III.3.1 Corrections (ER21-2850)	Sep 8	ISO-NE files conforming changes to eTariff § III.3.1
			Sep 10	NEPOOL intervenes

V. OATT Amendments / TOAs / Coordination Agreements

	12	BTM Generation Proposal (ER21-2337)	Sep 20	ISO-NE files responses to Aug 20 deficiency letter; comment deadline ***Oct 12, 2021***

	12	Updated CONE, Net Cone and PPR Values (eff. FCA16) (ER21-787)	Sep 23	FERC issues *Net CONE Allegheny Order*, modifying the discussion in, but sustaining the results of, the *May 28 Orders*

V. Financial Assurance/Billing Policy Amendments

*	13	eTariff FAP Attachment 3 Corrections (ER21-2815)	Sep 1	ISO-NE submits corrections to eTariff FAP to reinstate previously-accepted text in Attachment 3 that was inadvertently omitted in subsequently-accepted eTariff filings; comment deadline Sep 22, 2021
			Sep 8, 10	Calpine, NEPOOL intervene

VI. Schedule 20/21/22/23 Changes

No Activity to Report

VII. NEPOOL Agreement/Participants Agreement Amendments

*	14	Waiver Agreement: PA Board Provisions (not docketed)	Sep 24	NEPOOL and ISO-NE submit an informational filing advising the FERC of the waiver of PA §§ 9.2.2 and 9.2.3(a)

VIII. Regional Reports

	15	Capital Projects Report - 2021 Q2 (ER21-2632)	Oct 1	FERC accepts 2021 Q2 Report, eff. Jul 1, 2021
*	16	Reserve Market Compliance (31st) Semi-Annual Report (ER06-613)	Oct 1	ISO-NE submits 31st semi-annual report

IX. Membership Filings

*	16	Oct 2021 Membership Filing (ER21-2985)	Sep 30	***New Members***: CPV Valley, GB CT, GB M&M, JPMVEC, Oxford Energy Center, Naugatuck Avenue Storage, Norman Street ES, and Westfield ESS; ***Name Change***: Rhode Island Bioenergy Facility, LLC; comment deadline ***Oct 21, 2021***
	17	Aug 2021 Membership Filing (ER21-2558)	Sep 27	FERC accepts (i) the memberships of In Commodities US and Jupiter Power; (ii) the termination of the Participant status of GenOn Energy Management and GenOn Canal; and (iii) the name change of Rivercrest Power-SOUTH, LLC
*	17	Suspension Notice – Manchester Methane, LLC (not docketed)	Sep 17	ISO-NE files notice of suspension of Manchester Methane, LLC from the New England Markets
			Oct 5	Manchester Methane default cured; suspension lifted

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

*	17	Revised Rel. Standards: CIP-013-2, CIP-005-7, CIP-010-4 (RD21-2)	Sep 15	NERC files for approval proposed changes to CIP-004-7 and CIP-011-3 to clarify protections required regarding use of third-party solutions for BES Cyber System Information; comment deadline ***Oct 6, 2021***
*	19	Rules of Procedure Changes (CMEP Risk-Based Approach Enhancements) (RR21-10)	Sep 29	NERC files for approval changes to ROP § 400 and 1500 and Appendices 2 and 4C; comment deadline ***Oct 20, 2021***
	20	2022 NERC/NPCC Business Plans and Budgets (RR21-9)	Sep 29	NERC submits Budget Amendment to include additional Fixed Asset expenditures; comment deadline ***Oct 12, 2021***

XI. Misc. - of Regional Interest

*	21	203 Application: PSEG/Generation Bridge II (ArcLight) (EC21-125)	Sep 2 Sep 28	PSEG Project Companies and Generation Bridge II requested authorization for a transaction pursuant to which 100% of the membership interests in the PSEG Project Companies will be sold to Generation Bridge II, a wholly-owned, indirect subsidiary of ArcLight Fund VII, which is itself affiliated with Great River Hydro Applicants submit corrections to an affidavit included in the original filing; comment deadline ***Nov 29, 2021***
	21	203 Application: Cypress Creek/EQT (EC21-108)	Oct 1	FERC authorizes Catalyst (EQT) acquisition of Cypress Creek Renewables
	22	203 Application: Seneca/Rice et al. (EC21-84)	Sep 24	Archaea provides notice that this FERC-authorized transaction was consummated on Sep 15, 2021
*	23	CL&P/EIP E&P Agreement (ER21-2880)	Sep 13	CL&P files E&P Agreement
*	23	IA Termination: CL&P/Sterling Property (ER21-2860)	Sep 9 Sep 22 Sep 30	CL&P files a notice of termination of a 2002 IA governing service to a 26 MW waste-tire fueled generator located in Sterling, CT Brookfield intervenes Sterling Property protests termination notice
	23	Seabrook/NECEC E&P Agreement (ER21-2719)	Oct 4	FERC accepts E&P Agreement, eff. Aug 20, 2021
	24	LGIA: National Grid / New England Wind (Hoosac) (ER21-2548)	Sep 24	FERC accepts LGIA, eff. Mar 19, 2021
	24	Versant Waiver Request: Unreserved Transmission Use Penalty Policy (ER21-2447)	Sep 27	FERC dismisses the waiver request as inappropriate (because the policy for which Versant sought waiver was a business rule that was not part of the tariff on file with the FERC)
	25	IRH Support and Use Agreements eTariff Compliance Filings (ER21-2163 et al.)	Sep 16	FERC accepts changes to VETCO's Phase I VT Transmission Line Support Agreement filing (ER21-2158), eff. Jan 1, 2021
	25	*Orders 864/864-A* (Public Util. Trans. ADIT Rate Changes): New England Compliance Filings (various)	Sep 15 Sep 29 Sep 30	*ER20-2429-001 (CMP)*. FERC issues second deficiency letter *ER20-2429-001 (CMP)*. CMP requests extension of time to respond to second deficiency letter. *ER20-2429-001 (CMP)*. FERC grants extension of time to respond to second deficiency letter to ***Oct 22, 2021***

XII. Misc. - Administrative & Rulemaking Proceedings

26	Joint Federal-State Task Force on Electric Transmission (AD21-15)	Sep 10	Comments on agenda topics filed by AEP, APPA, the Environmental Law and Policy Center and National Audubon Society, ITC, NYU's Institute for Policy Integrity, Shell, Southern Company Services, Wires
27	Climate Change, Extreme Weather, and Elec. Sys. Reliability: Jun 1-2 Tech. Conf. (AD21-13)	Sep 23 – 30	Post-technical conference comments submitted by CAISO; MISO; NYISO; PJM; AEP; City of New Orleans; City of New York; Columbia Law School's Sabin Center for Climate Change Law; EDF and Sabin Center for Climate Change Law; EEI; EPSA; Eversource; Exelon, Jupiter Intelligence; Louisville Gas and Electric Company and Kentucky Utilities Company; MI PSC; NRDC, Sierra Club, Sustainable FERC Project, and UCS; ODEC; NERC; C. Wright
27	Electrification and the Grid of the Future (AD21-12)	Sep 30	FERC posts transcript of April 29 tech conf in eLibrary

28	Reliability Technical Conference (AD21-11)	Sep 30 Sep 17- Oct 4	FERC holds annual Commissioner-led tech conf Speaker materials posted to eLibrary
28	Modernizing Electricity Market Design - Energy and Ancillary Service Markets (AD21-10)	Sep 3 Sep 7 Sep 14 Sep 13 – 20 Oct 1	FERC issues second supplemental notice (including speaker names) of Sep 14 tech conf FERC staff issues White Paper FERC holds the first of the 2 staff-led tech confs to discuss potential energy and ancillary services market reforms that may be needed as the resource fleet and load profiles change over time PJM, SPP, CAISO, Reliable Energy Analytics submit public comments FERC issues supplemental notice of Oct 12 tech conf (including panel topics and speaker names)
29	Office of Public Participation (AD21-9)	Sep 3 Sep 8	M.J. Bradley submits Summary of Stakeholder Feedback Provided Through Listening Sessions and Written Comments FERC issues notice that the virtual workshop to discuss technical assistance in electric proceedings, solicit public input on their technical assistance needs, and explore ways OPP could facilitate technical assistance to interested parties will be held on ***Oct 7, 2021*** rather than Sep 16, 2021 as previously noticed
30	Hybrid Resources (AD20-9)	Sep 8-21	ACRE, Clean Grid Alliance, EEI, the City of New York, Hybrid Resource Coalition, NRECA, Pine Gate Renewables, PJM IMM, UCS submit comments
31	ANOPR: Transmission Planning and Allocation and Generator Interconnection (RM21-17)	Sep 3 Sep 16 Sep 17	FERC denies IRC, OPSI and OMS request extension of time to submit comments; comment deadline remains ***Oct 12, 2021***; reply comment deadline extended to ***Nov 30, 2021*** FERC announces ***Nov 15, 2021*** staff-led, remote technical conference regarding regional transmission planning National Conference of State Legislatures submits comments
33	NOPR: Electric Transmission Incentives Policy (RM20-10)	Sep 10	FERC holds ***Sep 10 workshop***
34	*Order 2222/2222-A/2222-B*: DER Participation in RTO/ISO Markets (RM18-9)	Sep 21	ISO-NE submits second process status update

XIII. FERC Enforcement Proceedings

40	PacifiCorp (IN21-6)	Sep 14	OE answers PacifiCorp's Jul 19, 2021 answer
41	GreenHat (IN18-9)	Sep 3 Oct 1 Oct 5	OE issues notice that the date by which the FERC needs to issue a penalty order to ensure that a lawsuit against the Kittell Estate will be timely is ***Oct 11, 2021*** OE lawyers report on improper communications between decisional staff member and another lawyer working on the GreenHat litigation Kittell Estate moves that the FERC drop all enforcement action against the Estate, ban OE staff Messrs. Tabackman and Olson from any future involvement, and order other offices within the FERC to investigate
41	Rover Pipeline, LLC and Energy Transfer Partners, L.P. (IN19-4)	Sep 15	Rover answers OE's Jul 21 answer

42	Total Gas & Power North America, Inc. et al. (IN12-17)	Sep 1	Presiding ALJ Krolikowski issues order confirming her rulings from the Aug 26 prehearing conference and establishing a procedural schedule
		Sep 21	Chief Judge Cintron concurrently designates Judge Joel deJesus as Settlement Judge; first settlement conf ***Oct 15, 2021***
		Sep 24	Respondents and OE Staff move to temporarily suspend the procedural schedule for about six weeks
		Sep 28	Chief Judge Cintron grants Respondents' motion, extending the hearing commencement and initial decision deadlines to ***Sep 26, 2022*** and ***Feb 20, 2023***, respectively

XIV. Natural Gas Proceedings

44	Iroquois ExC Project (CP20-48)	Sep 2	FERC staff changes issuance date of its final EIS for the Project to ***Nov 12, 2021***
		Sep 3	FERC staff issues environmental information request #4
		Sep 13	Iroquois responds to environmental information request #4

XV. State Proceedings & Federal Legislative Proceedings

47	New England States' Vision Statement	Sep 23	ISO-NE Board responds to New England States' Vision Statement and Advancing the Vision Report

XVI. Federal Courts

48	CIP IROL Cost Recovery Rules (20-1389)	Sep 22	Court schedules oral argument for ***Nov 12, 2021***
48	Mystic 8/9 Cost of Service Agreement (20-1343 et al.)	Sep 7	Mystic and State Petitioners file Opening Briefs
		Sep 21	Intervenor for State Petitioners file their Brief
50	2013/14 Winter Reliability Program Order on Compliance and Remand (20-1289, 20-1366) (consol.)	Sep 29	Court allots 10 minutes per side; oral argument ***Oct 15, 2021*** before Judges Srinivasan, Henderson and Edwards
51	ISO-NE's Inventoried Energy Program Proposal (19-1224 et al.)		Oral argument ***Oct 21, 2021*** before Judges Wilkins, Katsas and Jackson
51	*Order 872* (20-72788 et al.) (9th Cir.)	Sep 27	Respondent's brief filed
52	PennEast Project (18-1128)	Sep 1	Parties file motion to govern future proceedings
		Sep 13	Court orders Petitioners and Respondents to file supplemental briefs on ***Nov 12, 2021***
52	*Opinion 569/569-A*: FERC's Base ROE Methodology (16-1325 et al.) (consol.)	Sep 22	Court schedules oral argument for ***Nov 18, 2021***

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: October 6, 2021

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 October 5, 2021. If you have questions, please contact us.

COVID-19

- **Remote ALJ Hearings (AD20-12)**

All hearings before Administrative Law Judges ("ALJs") are being held remotely through video conference software (WebEx and SharePoint) until further notice.[2] The Presiding Judge in each remote hearing will ensure that the participants have access to an "IT Day" prior to the hearing to allow all participants, witnesses, and the public who will attend the hearing to learn more about the remote hearing software and to get their technical questions answered by the appropriate FERC staff. Uniform Hearing Rules for all Office of the ALJ hearings were adopted effective September 15, 2020.[3] The "Remote Hearing Guidance for Participants" was revised on May 18, 2021 to make two additional changes.[4] The Uniform Hearing Rules and Remote Hearing Guidance for Participants are publicly available in this proceeding in eLibrary and on the FERC's Administrative Litigation webpage.

- **Extension of Filing Deadlines (AD20-11)**

On July 26, 2021, the wavier of FERC regulations that require that filings with the FERC be notarized or supported by sworn declarations was ***extended for an additional six months, through January 1, 2022***.[5] The July 26 notice extended the waiver first noticed in May[6] for a third time.[7] As previously reported, Entities may also seek waiver of FERC orders, regulations, tariffs and rate schedules, including motions for waiver of

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

[2] *Chief Administrative Law Judge's Notices to the Public*, Docket No. AD20-12 (June 17, 2020).

[3] *Chief Administrative Law Judge's Notices to the Public*, Docket No. AD20-12 (Sep. 1, 2020).

[4] *Chief Administrative Law Judge's Notices to the Public*, Docket No. AD20-12 (May 18, 2021) (requiring that only attorneys may access Live Litigation (§VI(a)(vii)) and encouraging that privileged sessions be limited and revising guidance on privileged versus public session management (§VI(k)).

[5] *See Extension of Non-Statutory Deadlines*, Docket No. AD20-11-000 (July 26, 2021) ("Third Extension").

[6] *Extension of Non-Statutory Deadlines*, Docket No. AD20-11-000 (May 8, 2020)("First Extension"); *Extension of Non-Statutory Deadlines*, Docket No. AD20-11-000 (Jan. 25, 2021) ("Second Extension").

[7] *See Extension of Non-Statutory Deadlines*, Docket No. AD20-11-000 (Aug. 20, 2020).

regulations that govern the form of filings, as appropriate, to address needs resulting from steps they have taken in response to the coronavirus.[8]

- **Blanket Waiver of ISO/RTO Tariff In-Person Meeting and Notarization Requirements (EL20-37)**

In light of the continuing nature of the COVID-19 National Emergency, the FERC extended on July 26, 2021, ***for an additional 6 months, through January 1, 2022***, the blanket waivers of ISO/RTO Tariff *in-person*[9] meeting and notarization requirements.[10] The July 26 order extended for a third time the blanket waivers first granted in the FERC's April 2, 2020 order and extended in orders issued August 20, 2020 and January 25, 2021.[11]

I. Complaints/Section 206 Proceedings

- **206 Investigation: ISO-NE Tariff Schedule 25 and Section I.3.10 (EL21-94)**

On September 7, 2021, the FERC instituted a proceeding under FPA Section 206 to consider whether Schedule 25 and Tariff section I.3.10 may be unjust and unreasonable.[12] This proceeding arises out of issues raised in the NECEC/Avangrid Complaint Against NextEra/Seabrook (related to the interconnection of the New England Clean Energy Connect transmission project ("NECEC Project")) summarized below (EL21-6). Specifically, the FERC identified a concern that "Schedule 25's definition of Affected Party and Tariff section I.3.10 may be unjust and unreasonable to the extent they may allow generating facilities and their components to be identified as facilities on which adverse impacts must be remedied before an elective transmission upgrade can interconnect to the ISO-NE transmission system, even though generators are not subject to the Commission's open access transmission principles," and could result in upgrades identified on an Affected Party's system without any obligation for the Affected Party to construct the identified upgrades.[13]

Accordingly, the FERC directed ISO-NE to: (1) show cause as to why Schedule 25 and Tariff section I.3.10 remain just and reasonable or (2) explain what changes to Schedule 25 and/or Tariff section I.3.10 it believes would remedy the identified concerns if the FERC were to determine that Schedule 25 and/or Tariff section I.3.10 has become unjust and unreasonable and proceeds to establish a replacement rate. ISO-NE's response is due on or before November 8, 2021. ISO-NE may make its filing pursuant to FPA section 206 (in which case interested parties would have 60 days (or until January 7, 2022) to address whether ISO-NE's existing Tariff remains just and reasonable and if not, what changes to ISO-NE's Tariff should be implemented as a replacement rate) or, should it prefer, pursuant to its applicable FPA section 205 filing rights (in which case comments from interested parties would be due in accordance with the usual 21-day deadlines set for such proceedings). The FERC noted its expectation that, if ISO-NE files changes to Schedule 25 and/or Tariff section I.3.10 that it believes would remedy the identified concerns within 60 days of the date of the *Sep 7 Order*, it would issue a final order within three months of ISO-NE's response.[14] On September 8, the FERC issued a notice of the proceeding and of the refund

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[8] *Extension of Non-Statutory Deadlines*, Docket No. AD20-11-000 (Apr. 2, 2020).

[9] The waiver only applies to a specific requirement that meetings be held *in person*. Other than the in-person requirement, such meetings must still be held consistent with the tariff, but should be conducted by other means (e.g. telephonically).

[10] *Temporary Action to Facilitate Social Distancing*, 176 FERC ¶ 61,044 (July 26, 2021).

[11] *Temporary Action to Facilitate Social Distancing*, 171 FERC ¶ 61,004 (Apr. 2, 2020) (waiving notarization requirements through Sep. 1, 2020, contained in any tariff, rate schedule, service agreement, or contract subject to the FERC's jurisdiction under the Federal Power Act ("FPA"), the Natural Gas Act ("NGA"), or the Interstate Commerce Act); *Temporary Action to Facilitate Social Distancing*, 172 FERC ¶ 61,151 (Aug. 20, 2020) (extending the waivers through Jan. 29, 2021); *Temporary Action to Facilitate Social Distancing*, 174 FERC ¶ 61,047 (Jan. 25, 2021) (extending the waivers through July 31, 2021).

[12] *NECEC Transmission LLC and Avangrid, Inc. v. NextEra Energy Resources, LLC et al. and ISO New England Inc.*, 176 FERC ¶ 61,148 (Sep. 7, 2021) ("*Sep 7 Order*").

[13] *Id.* at P 20.

[14] *Id.* at P 26.

effective date, which will be October 13, 2020 (the date the NECEC/Avangrid Complaint Against NextEra/Seabrook was filed). Those interested in participating in this proceeding were required to intervene on or before October 5, 2021.[15] NEPOOL, NESCOE, Brookfield, Calpine, Dominion, Eversource, HQ US, LS Power, MA AG, MMWEC, National Grid, NECEC Transmission, NEPGA, NextEra, NRG, CT DEEP, MA DOER, American Clean Power Association ("ACPA"), EPSA, RENEW Northeast, and Public Citizen intervened. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

The *Sep 7 Order* was summarized for the Reliability Committee by NEPOOL counsel at the RC's September 21 meeting. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Green Development DAF Charges Complaint Against National Grid (EL21-47)**

On September 23, 2021, the FERC denied in part, but granted in part, the complaint ("Complaint")[16] by Green Development, LLC ("Green Development") against New England Power Company and Narragansett Electric Company (together, "National Grid" or "Grid").[17] The *Complaint Order* partially denied the Complaint, finding that Green Development did not meet its burden of proof that the assignment of DAF charges violated the first part of the ISO-NE Tariff definition of Direct Assignment Facilities (requiring that the facilities be constructed for the sole use/benefit of a particular Transmission Customer requesting service under the ISO-NE Tariff).[18] However, the *Complaint Order* found that Green Development demonstrated a failure by National Grid to comply with the requirement that the facilities be "specified in a separate agreement among ISO-NE, the Interconnection Customer and the Transmission Customer, as applicable, and the Transmission Owner whose transmission system is to be modified."[19] As a result, National Grid is not permitted, unless and until it complies with that part of the definition, to assess DAF charges to Narragansett in association with the upgrades necessary for the Projects.[20] Challenges to the *Green Development Complaint Order* are due on or before October 25, 2021. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **NEPGA Net CONE Complaint (EL21-26)**

On September 23, 2021, the FERC issued an "*Allegheny Order*"[21] addressing arguments raised in a joint request for rehearing by the Electric Power Supply Association ("EPSA") and the New England Power Generators Association ("NEPGA") of the *NEPGA Net CONE Complaint Order*[22] and the *Updated CONE, Net Cone and PPR Values Order*[23] (together, the "*May 28 Orders*"). While "[p]ursuant to *Allegheny Defense Project v. FERC*, the

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[15] The *Notice* was published in the *Fed. Reg.* on Sep. 14, 2021 (Vol. 86, No. 175) p. 51,140.

[16] The Complaint requested a finding that Grid's assessment of Direct Assignment Facility ("DAF") charges for Green Development's projects is unauthorized under the ISO-NE Tariff (the "Complaint").

[17] Green Development, LLC v. New England Power Co. and Narragansett Elec. Co., 176 FERC ¶ 61,193 (Sep. 23, 2021) ("*Green Development Complaint Order*" or "*Complaint Order*")).

[18] *Id.* at PP 54-55, 59-60.

[19] *Id.* at PP 54, 61-62.

[20] *Id.* at P 62.

[21] *ISO New England Inc. and New England Power Generators Association, Inc. v. ISO New England Inc.*, 176 FERC ¶ 61,176 (Sep. 23, 2021) ("*Net Cone Allegheny Order*").

[22] *New England Power Generators Assoc., Inc. v. ISO New England Inc.*, 175 FERC ¶ 61,177 (May 28, 2021) ("*NEPGA Net Cone Complaint Order*"), *reh'g denied*, 176 FERC ¶ 62,058 (July 29, 2021). As previously reported, The Complaint alleged that ISO-NE violated its Tariff and the filed-rate doctrine by recalculating and reviewing with NEPOOL a Net CONE value methodology demonstrably inconsistent with the Tariff and prior practice. NEPGA sought an order directing ISO-NE to recalculate, review with NEPOOL stakeholders, and file with the FERC a Net CONE value consistent with the existing Tariff definition.

[23] *ISO New England Inc.,* 175 FERC ¶ 61,172 (May 28, 2021) ("*Updated CONE, Net Cone and PPR Values Order*"), *reh'g denied*, 176 FERC ¶ 62,059 (July 29, 2021).

rehearing request filed in this proceeding may be deemed denied by operation of law[24] … as permitted by section 313(a) of the FPA, [the FERC modified] the discussion in",[25] but sustained the results of, the *May 28 Orders*. Notably, the FERC found that: (i) "ISO-NE's estimates are just and reasonable notwithstanding the possibility that other estimates may also be reasonable";[26] (ii) the Tariff and filed rate doctrine did not require that the methodology underlying the calculation of Net CONE be anything other than the approved methodology on file at the time the Net CONE values are implemented,[27] and it had appropriately determined that ISO-NE was entitled to base its recalculations on the definition it intended to file and have in effect in advance of that FCA.[28]

Neither of the *May 28 Orders* were appealed to a Federal Court and this proceeding is now concluded. 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).

- **NECEC/Avangrid Complaint Against NextEra/Seabrook (EL21-6)**

As previously reported, NECEC Transmission LLC ("NECEC") and Avangrid Inc. (together, "Avangrid") filed a complaint (the "Complaint") on October 13, 2020 requesting FERC action "to stop NextEra from unlawfully interfering with the interconnection of the NECEC Project and seeking, among other things, an initial, expedited order that would grant certain relief[29] and direct NextEra to immediately commence engineering, design, planning and procurement activities that are necessary for NextEra to construct the generator owned transmission upgrades during Seabrook Station's Planned 2021 Outage. NextEra submitted an answer to the October 13 Complaint (requesting the FERC dismiss or deny the Complaint) and National Grid filed comments. Doc-less interventions were filed by Dominion, Eversource, Calpine, Exelon, HQ US, MA AG, MMWEC National Grid, NESCOE, NRG, and Public Citizen. Avangrid answered NextEra's answer and NextEra answered Avangrid's November 17 answer ("supplemental answer"), repeating its request that the FERC dismiss or deny the Complaint. Avangrid also answered the supplemental answer.

Avangrid amended the Complaint on March 26, 2021 to reflect that aspects of the relief originally requested in the Complaint are no longer feasible within the timeline previously sought. Avangrid continues to seek expeditious FERC action, requesting in its March 26 filing a FERC order on or before May 7, 2021 (which did not occur). On April 15, 2021, NextEra answered the amended Complaint. On April 20, 2021, Avangrid answered NextEra's April 15 answer. On May 6, 2021, ISO-NE submitted a letter to express importance of prompt resolution of these matters. On May 17, Avangrid submitted a letter supporting ISO-NE's May 6, 2021 letter.

Order Establishing Additional Briefing. On September 7, 2021, the FERC issued an order establishing additional briefing in this proceeding and instituted a broader Section 206 proceeding (*see* EL21-94 above).[30] Specifically, with respect to this proceeding, the FERC requested additional briefing from the Parties, as well as from ISO-NE, on the following issues:

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[24] *See* Notice of Denial of Rehearing by Operation of Law and Providing for Further Consideration, *New England Power Generators Assoc., Inc. v. ISO New England Inc.*, 176 FERC ¶ 62,058 (July 29, 2021).

[25] *Id.* at P 2.

[26] *Id.* at P 8.

[27] *Id.* at P 14.

[28] *Id.* at P 15.

[29] Directing NextEra to comply with the ISO-NE OATT, to comply with open access requirements, and to cease and desist unlawful interference with the NECEC Project; and to have the FERC temporarily revoke NextEra's blanket waiver under Part 358 of the FERC's regulations and to initiate an investigation and require NextEra to preserve and provide documents related to the interconnection of the NECEC Project.

[30] *NECEC Transmission LLC and Avangrid, Inc. v. NextEra Energy Resources, LLC et al. and ISO New England Inc.*, 176 FERC ¶ 61,148 (Sep. 7, 2021).

- ♦ Whether or not Seabrook's breaker is properly identified as a part of Seabrook's generating facility.
- ♦ If Seabrook's breaker is part of Seabrook's generating facility, under what authority, if any, Seabrook may be subject to the upgrade obligations imposed on Affected Parties under the ISO-NE Tariff.
- ♦ If Seabrook's breaker is part of Seabrook's generating facility, what obligations, if any, Seabrook has under its LGIA with respect to replacement of the breaker and whether or not ISO New England Operating Documents and Applicable Reliability Standards impose an obligation to replace the breaker. If Seabrook's breaker is appropriately classified as a system protection facility, what obligations Seabrook has to replace the breaker. If the Seabrook LGIA obligates Seabrook to act, a description of the scope of Seabrook's obligation under the LGIA.
- ♦ Whether there exists any solution for the interconnection of the NECEC Project that may be implemented without the replacement of Seabrook's breaker.
- ♦ If replacement of Seabrook's breaker is necessary for the interconnection of the NECEC Project, whether there exists any interim solution for the interconnection of the NECEC Project that would allow energization of the NECEC Project prior to the replacement of Seabrook's breaker.

Initial briefs responsive to these questions are due on or before October 7, 2021. Reply briefs are due on or before October 22, 2021. The September 7 order was summarized for the Reliability Committee ("RC") by NEPOOL counsel at the RC's September 21 meeting. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **NextEra Energy Seabrook Declaratory Order Petition re: NECEC Elective Upgrade Costs Dispute (EL21-3)**

In a related matter, initiated a week earlier than the Avangrid Complaint, NextEra Energy Seabrook, LLC ("Seabrook") filed a Petition for a Declaratory Order ("Petition") "by which it seeks to understand the scope of its FERC-jurisdictional regulatory obligations with respect to the project ("NECEC Elective Upgrade"), and to resolve its dispute with NECEC". Specifically, Seabrook asked the FERC to declare that: (1) Seabrook is not required to incur a financial loss to upgrade, for NECEC's sole benefit, a 24.5 kV generator circuit breaker and ancillary equipment ("Generation Breaker") at Seabrook Station; (2) "Good Utility Practice" for replacement of the nuclear plant Generation Breaker is defined in terms of the practices of the nuclear power industry, such that Seabrook's proposed definition of that term is appropriate for use in a facilities agreement with NECEC; and (3) Seabrook will not be liable for consequential damages for the service it provides to NECEC under a facilities agreement (collectively, the "Requested Declarations"). Alternatively, Seabrook asked that the FERC declare that nothing in ISO-NE's Tariff requires Seabrook to enter into an agreement to replace the Generation Breaker, and therefore, Seabrook and the Joint Owners are entitled to bargain for appropriate terms and conditions to recover their costs, to define Good Utility Practice, and to limit liability associated with providing the service ("Alternative Declaration").

Comments on Seabrook's Petition were filed by Eversource, MMWEC and NEPGA. Avangrid and NECEC Transmission ("Avangrid") protested the Declaratory Order Petition. Doc-less interventions were filed by Avangrid, Dominion, Eversource, Calpine, Exelon, HQ US, National Grid, NESCOE, NRG, and Public Citizen. NextEra answered Avangrid's protest and Avangrid answered NextEra's answer. On May 6, 2021, ISO-NE submitted a letter in this proceeding, as well as in EL21-6, to express importance of prompt resolution of these matters. There has been no activity in this proceeding since the last Report and this matter also remains pending before the FERC. 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,[31] set the TOs' Base ROE at 10.57% (reduced from 11.14%), capped the TOs' total ROE (Base ROE *plus* transmission incentive adders) at 11.74%, and required implementation effective as of October 16, 2014 (the date of *Opinion 531-A*).[32] However, the FERC's orders were challenged, and in *Emera Maine,*[33] the DC Circuit 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)[34] and third (EL14-86)[35] 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.[36] 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[37] also went to hearing before an ALJ, Judge Glazer, who issued his initial decision on March 27, 2017.[38] The *Base ROE IV Initial Decision* concluded that the currently-filed base ROE of 10.57%, which may reach a

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[31] 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 clarif.*, 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*")).

[32] *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*").

[33] *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).

[34] 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%.

[35] The 2014 Base ROE Complaint, filed July 31, 2014 by the Massachusetts Attorney General, 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.

[36] *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*").

[37] 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 XVI below, have been appealed to, and are pending before, the DC Circuit.

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

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.[39] Parties in this proceeding filed briefs on exception to the FERC, which has not yet issued an opinion on the *Base ROE IV Initial Decision*.

October 16, 2018 Order Proposing Methodology for Addressing ROE Issues Remanded in Emera Maine and Directing Briefs. On October 16, 2018, the FERC, addressing the issues that were remanded in *Emera Maine,* proposed a new methodology for determining whether an existing ROE remains just and reasonable.[40] The FERC indicated its intention that the methodology be its policy going forward, including in the four currently pending New England proceedings (*see*, however, *Opinion 569-A*[41] (EL14-12; EL15-45) in Section XI below). The FERC established a paper hearing on how its proposed methodology should apply to the four pending ROE proceedings.[42]

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%.[43] 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

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

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

[41] *Ass'n of Buss. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569-A, 171 FERC ¶ 61,154 (2020) ("*Opinion 569-A*"). The refinements to the FERC's ROE methodology included: (i) the use of the Risk Premium model instead of only relying on the DCF model and CAPM under both prongs of FPA Section 206; (ii) adjusting the relative weighting of long- and short-term growth rates, increasing the weight for the short-term growth rate to 80% and reducing to 20% the weight given to the long-term growth rate in the two-step DCF model; (iii) modifying the high-end outlier test to treat any proxy company as high-end outlier if its cost of equity estimated under the model in question is more than 200% of the median result of all the potential proxy group members in that model before any high- or low-end outlier test is applied, subject to a natural break analysis. This is a shift from the 150% threshold applied in *Opinion 569*; and (iv) calculating the zone of reasonableness in equal thirds, instead of using the quartile approach that was applied in *Opinion 569*.

[42] *Id.* at P 19.

[43] *Id.* at P 59.

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[44] 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, 2019. The Louisiana PSC answered the TOs' January 24 motion on February 12. Reply briefs were due March 8, 2019 and were submitted by the TOs, Complainant-Aligned Parties, EMCOS, and 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*[45] 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, 2020, EMCOS and CAPs opposed the TOs' request and brief.

These matters remain 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

- **VTransco Request to Defer 2021/22 Retiree Lump Sum Payment Cost Recovery (ER21-2627)**

On September 22, 2021, the FERC authorized Vermont Transco ("VTransco") to defer for future recovery costs associated with lump sum payments to employees who retire in 2021 and 2022.[46] As previously reported, VELCO expects a record number of employees to retire in 2021 (12) and 2022 and anticipates that many, if not most, of them will opt to take a lump sum payment, resulting in significantly higher one-time expenses to be passed through to VTransco than has historically been the case. VTransco's request is intended to mitigate the rate impact on the Vermont distribution utilities, and in turn, their retail ratepayers. The deferral was accepted effective December 31, 2021, as requested. Unless the September 22 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **CSC Request for Regulatory Asset Recovery of Previously-Incurred CIP IROL Costs (ER21-2334)**

On August 31, 2021, the FERC denied the request by Cross-Sound Cable Company LLC ("CSC") for authorization to establish a regulatory asset that would include all CIP-IROL Costs[47] that CSC prudently incurred between January 1, 2016 and May 31, 2021 ($1.324 million) and recover those costs under Schedule 17 (from all ISO-NE transmission customers) over a five-year period (beginning on the date the FERC makes

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

[45] *Ass'n of Buss. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569, 169 FERC ¶ 61,129 (Nov. 21, 2019) ("*MISO ROE Order*"), *order on reh'g*, Opinion No. 569-A, 171 FERC ¶ 61,154 (May 21, 2020).

[46] *Vermont Transco LLC*, Docket No. ER21-2627 (Sep. 22, 2021) (unpublished letter order).

[47] Interconnection Reliability Operating Limits ("IROL") Critical Infrastructure Protection ("CIP") costs under Schedule 17 of the ISO-NE Tariff.

this rate treatment and related cost recovery effective).[48] Relying on its *Schedule 17 Orders*,[49] which found that Schedule 17 permits recovery only of CIP-IROL costs incurred on or after the effective date of a FPA section 205 filing made by an IROL-Critical Facility owner to recover such costs, and recovery of CIP-IROL costs incurred prior to the effective date of any relevant, individual FPA section 205 filing would violate the rule against retroactive ratemaking, the FERC found that permitting the recovery here proposed by CSC would violate the filed rate doctrine.[50] The FERC rejected the alternative bases for FERC approval proposed by CSC.[51]

Request for Rehearing. On September 30, 2021, CSC requested rehearing of the *August 31 Order*. The CSC request for rehearing is pending, with FERC action required on or before November 1, 2021, or the request will be deemed denied by operation of law.

If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

As previously reported, the FERC issued four orders in this proceeding in July 2020 (three on July 17 (together, the "*July 17 Orders*"); one on July 28, 2020). Each of the orders addressed in part or in whole the Cost-of-Service Agreement ("COS Agreement")[52] among Constellation Mystic Power ("Mystic"), Exelon Generation Company ("ExGen") and ISO-NE, which is to provide compensation for the continued operation of the Mystic 8 & 9 units from June 1, 2022 through May 31, 2024. As noted in Section XVI below, each of the *July 17 Orders*[53] (and the earlier, underlying orders) have been appealed to the DC Circuit. On July 15, 2021, the FERC issued an order setting the base ROE for the Mystic COS Agreement at 9.33%.[54] Activity since the last Report includes:

Requests for Rehearing of the Mystic ROE Order Denied by Operation of Law (-010, -011). On September 13, 2021, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further

[48] *Cross-Sound Cable Co., LLC*, 176 FERC ¶ 61,073 (Aug. 31, 2021) ("*August 31 Order*").

[49] *ISO New England Inc.,* 171 FERC ¶ 61,160 ("*Schedule 17 Order*"), *order on reh'g*, 172 FERC ¶ 61,251 (2020) ("*Schedule 17 Rehearing Order*") (collectively, "*Schedule 17 Orders*"), *appeal pending sub nom.*, *Cogentrix Energy Power Mgmt., LLC v. FERC*, D.C. Cir. No. 20-1389 (filed Oct. 14, 2020) (*see* Section XVI).

[50] *August 31 Order* at P 33.

[51] *Id.* at PP 33-37. As previously reported, CSC proposed three alternative bases upon which the FERC could grant its request to use a regulatory asset for CIP IROL cost recovery and rate treatment: (i) FPA section 219 and Order 679 (incentive rate framework); FPA section 205 (in furtherance of the FERC's expressed policy of ensuring reliability of the BES in response to cybersecurity threats); or (iii) FPA section 309 (FERC's remedial authority). In the *August 31 Order*, the FERC rejected each of these in turn.

[52] 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.

[53] The "*July 17 Orders*" are the *July 2018 Rehearing Order, Dec 2018* Rehearing *Order* and the *July 17 Compliance Order. Constellation Mystic Power, LLC,* 164 FERC ¶ 61,022 (July 13, 2018) ("*July 2018 Order*"), *clarif. granted in part and denied in part, reh'g denied*, 172 FERC ¶ 61,043 (July 17, 2020) ("*July 2018 Rehearing Order*"); *Constellation Mystic Power, LLC*, 165 FERC ¶ 61,267 (Dec. 20, 2018) ("*Dec 2018 Order*"), *set aside in part, clarification granted in part and clarification denied in part*, 172 FERC ¶ 61,044 (July 17, 2020) ("*Dec 2018* Rehearing *Order*"); *Constellation Mystic Power, LLC*, 172 FERC ¶ 61,045 (July 17, 2020) ("*July 17 Compliance Order*") (order on compliance and directing further compliance).

[54] *Constellation Mystic Power, LLC,* 176 FERC ¶ 61,019 (July 15, 2021) ("*Mystic ROE Order*").

Consideration".[55] The Notice confirmed that the 60-day period during which a petition for review of the *Mystic ROE Order* can be filed with an appropriate federal court was triggered when the FERC did not act on the requests for rehearing of the *Mystic ROE Order* filed by Mystic, CT Parties,[56] ENECOS,[57] and the MA AG. The Notice also indicated that the FERC would address, as is its right, the rehearing requests in a future order, and may modify or set aside its orders, in whole or in part, "in such manner as it shall deem proper."

ROE (Fifth) Compliance Filing (-012). On August 16, 2021, Mystic filed a revised COS Agreement in a fifth compliance filing, this time in response to the *Mystic ROE Order*: (1) changing the Cost of Common Equity figures from 10.71 percent to 9.33 percent in Schedule C of the Methodology, for both Mystic 8&9 and Everett Marine Terminal ("Everett"); and (ii) reducing the Annual Fixed Revenue Requirements ("AFRR") to $170,605,963 for the 2022/2023 Capacity Commitment Period ("CCP") and to $139,668,204 for the 2023/2024 CCP. In addition, because the ROE adjustment reduces the charge for regassification service from Everett and the return on investment in Everett, Mystic also submitted for information a revised Fuel Supply Agreement ("FSA") and Terminal Services Agreement ("TSA") with Distrigas of Massachusetts LLC. Comments on the fifth compliance filing are due on or before September 7, 2021; none were filed. The fifth compliance filing is pending before the FERC.

2021 Capital Expenditures Informational Filing. On September 15, 2021, Mystic submitted, as required by orders in this proceeding and Sections I.B.1.i. and II.6.of Schedule 3A of the COS Agreement ("Protocols") its "2021 Filing" informational filing to provide support for the capital expenditures and related costs that Mystic projects will be collected as an expense between June 1, 2022 to December 31, 2022 ("2022 CapEx Projects"). This filing was not noticed for public comment by the FERC.

If you have questions on any aspect of this proceeding, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **2021/22 Power Year Transmission Rate Filing (ER09-1532; RT04-2)**

On July 30, 2021, the Participating Transmission Owners ("PTOs") Administrative Committee ("PTO AC") submitted a filing identifying adjustments to regional transmission service charges under Section II of the ISO Tariff for the period June 1, 2021 through May 31, 2022. The filing reflected the charges to be assessed under annual transmission formula rates, reflecting actual 2020 cost data, Forecasted Annual Transmission Revenue Requirements associated with projected PTF additions for the 2019 Forecast Period, and the Annual True-up including associated interest. The PTO AC states that the annual updates results in a Pool "postage stamp" RNS Rate of $140.98 /kW-year effective June 1, 2021, an increase of $11.72 /kW-year from the charges that went into effect on June 1, 2020. Effective January 1, 2022 through December 31, 2022, the Pool RNS Rate will either be $143.73/kW-year (a $2.75 increase from the Pool RNS Rate of $140.98/kW-year that went into effect on June 1, 2021), or will be $142.78/kW-year (a $1.80 increase), should the PTOs receive FERC approval in calendar year 2021 of their respective *Order 864* compliance filings. In addition, the annual update to the Schedule 1 formula rate results in a charge of $1.869 kW-year, a $0.124/kW-year increase from the Schedule 1 charge that last went into effect on June 1, 2021. This filing was not noticed for public comment. If there are questions on this proceeding, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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[55] *Constellation Mystic Power, LLC*, 176 FERC ¶ 62,127 (Sep. 13, 2021) (Notice of Denial By Operation of Law of Rehearings of Mystic ROE Order).

[56] "CT Parties" are: the Conn. Pub. Utils. Reg. Authority ("CT PURA"), the Conn. Dept. of Energy and Environ. Protection ("CT DEEP"), and the Conn. Office of Consumer Counsel ("CT OCC").

[57] As noted in previous Reports, "ENECOS" are Braintree, Concord, Georgetown, Hingham, Littleton Electric Light & Water, Middleborough, Middleton, Norwood, Pascoag, Reading, Taunton, and Wellesley.

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

- **eTariff § III.3.1 Corrections (ER21-2850)**

On September 8, ISO-NE filed conforming changes to eTariff § III.3.1 to ensure that the eTariff Viewer reflects changes accepted in ER21-1974 (Solar Data Requirements & Relocation of Wind Data Requirements) but inadvertently omitted in later changes filed in ER21-2220 (Removal of Appendix B from Market Rule 1; Deletion of Assoc. Tariff Provisions). Comments on the corrections were due on or before September 29, 2021; none were filed. NEPOOL filed 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).

- **ORTP Jump Ball Filing (ER21-1637)**

As previously reported, the FERC accepted in part and rejected in part pieces of ISO-NE's and NEPOOL's proposals, effective June 8, 2021.[58] Specifically, the FERC accepted NEPOOL's proposed ORTP value for battery storage and NEPOOL's proposed federal tax credits adjustments to the ORTPs for PV solar resources for FCA17 and FCA18. Otherwise, the FERC accepted ISO-NE's proposed ORTP values (including ISO-NE's Offshore Wind ORTP value (on which the Commissioners split 3-2; *see* separate dissents by Commrs. Glick and Clements, who agreed with NEPOOL's Offshore Wind ORTP)) and ISO-NE's proposal to maintain the current Tariff language regarding economic life determination and the establishment of ORTPs for hybrid and co-located resources in the FCM (rejecting NEPOOL's proposed Tariff revisions in each case). The FERC also rejected NEPOOL's proposal to require ISO-NE to account for future federal tax credit changes through the Tariff's indexing process, finding instead that such changes are more appropriately made through a FERC filing when and if such changes are made. With respect to other issues, the FERC rejected (i) Generation Owners' argument that accepting either the ISO-NE-proposed or the NEPOOL-proposed ORTPs for FCA16 would violate the filed rate doctrine or the rule against retroactive ratemaking;[59] and (ii) arguments about the MOPR (as outside the scope of this proceeding). In light of this outcome, the FERC directed ISO-NE to submit a compliance filing on or before June 22, 2021 that combines the alternative proposals as accepted by the FERC.

Request for Rehearing of ORTP Jump Ball Order (-002) Denied; ORTP Jump Ball Order Discussion Modified; Result Unchanged*.* Clean Energy Advocates[60] request for rehearing of the *ORTP Jump Ball Order* was denied by operation of law on August 6, 2021.[61] As is its right under section 313(a) of the FPA, the FERC then later issued an order, on August 26, 2021, modifying the discussion in the *ORTP Jump Ball Order* but reaching the same result.[62] In the *ORTP Jump Ball Allegheny Order*, the FERC explained why it found unpersuasive Clean Energy Advocates' arguments raised on rehearing. Dissenting in part, Chairman Glick and Commission Clements again stated that the FERC should have instead adopted NEPOOL's proposed capital cost estimate for offshore wind resources, finding they "better reflect current market activity compared to ISO-NE's estimates that are based on outdated and proprietary data". Challenges, if any, to the *ORTP Jump Ball Order* and the *ORTP Jump Ball Allegheny Order* must be filed in Federal Court on or before October 25, 2021. If you have any questions concerning this proceeding, please contact Dave Doot (dtdoot@daypitney.com; 860-275-0102), Sebastian Lombardi (860-275-0663; slombardi@daypitney.com), Joe Fagan (202-218-3901; jfagan@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

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[58] *ISO New England Inc.*, 175 FERC ¶ 61,195 (June 7, 2021) ("*ORTP Jump Ball Order*").

[59] *Id.* at P 127 et seq.

[60] "Clean Energy Advocates" are Conservation Law Foundation ("CLF"), Natural Resources Defense Council ("NRDC"), Sierra Club, RENEW Northeast, Inc. ("RENEW"), and Sustainable FERC Project.

[61] *See* Notice of Denial of Rehearing by Operation of Law and Providing for Further Consideration, *ISO New England Inc.*, 176 FERC ¶ 62,068 (Aug. 9, 2021).

[62] *ISO New England Inc*., 176 FERC ¶ 61,125 (Aug. 26, 2021) ("*ORTP Jump Ball Allegheny Order*").

- **Updated CONE, Net Cone and PPR Values (eff. FCA16) (ER21-787)**

As previously reported, the FERC conditionally accepted on May 28, 2021,[63] eff. May 29, 2021, the updates to the CONE, Net CONE and PPR values, as amended in ISO-NE's March 30, 2021 Deficiency Response,[64] as well as the modified definition of Net CONE, subject to a compliance filing that reflects the assumption that the reference unit has on-site compression.[65] ISO-NE submitted on June 11, 2021, and the FERC accepted on July 30, 2021,[66] that compliance filing, which updated the CONE, Net CONE and PPR values to $12.400, $7.468 and $9,337, respectively, to reflect the cost of gas compression.

As summarized more fully in Section II above (EL21-26), the FERC, in its September 23, 2021 *Net Cone Allegheny Order,* addressed arguments raised in a joint request for rehearing by EPSA and NEPGA of the *May 28 Orders*, including the *Updated CONE, Net Cone and PPR Values Order* in this proceeding. The FERC modified the discussion in, but sustained the results of, the *May 28 Orders*. Neither of the *May 28 Orders* were appealed to a Federal Court and this proceeding is now concluded. 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).

IV. OATT Amendments / TOAs / Coordination Agreements

- **BTM Generation Proposal (ER21-2337)**

On July 1, 2021, ISO-NE and the Participating Transmission Owners Administrative Committee ("PTO AC") jointly filed revisions to Tariff sections I and II to clarify that the calculation of Monthly Regional Network Load excludes load served by behind-the-meter ("BTM") generation, which does not participate in the New England wholesale markets as a Generator Asset, as well as the portions of a Generator Asset utilized to net load at the same retail meter ("BTM Generation Proposal"). The Participants Committee supported the BTM Generation Proposal at its June 3, 2021 meeting (Consent Agenda Items #3 and 4). Comments on this filing were due on or before July 22, 2021. Comments and protests were filed by NEPOOL, the ISO-NE IMM, AEE, IECG, NECOS/ENE, NEPGA, Public Systems, MPUC/CT PURA/MA DPU, and the VT PUC. Doc-less interventions were filed by Calpine, EMI, IECG, National Grid, NESCOE, and NRG. The PTO AC answered the NEPGA protest on August 6, 2021. Answers to the PTO AC Answer were filed by NEPGA and the IMM on August 13 and August 16, respectively. Since the last Report, IECG filed an answer to the NEPGA and IMM answers.

August 20, 2021 Deficiency Letter. On August 20, 2021, the FERC issued a deficiency letter, directing ISO-NE to provide within 30 days additional information and clarifications. The responses to the Deficiency Letter were due and were filed by ISO-NE on September 20, 2021. The responses to the deficiency letter re-set the 60-day deadline for FERC action on this filing. Comments on ISO-NE's deficiency letter responses are due on or before

[63] *ISO New England Inc.,* 175 FERC ¶ 61,172 (May 28, 2021) ("*Updated CONE, Net Cone and PPR Values Order*"), *reh'g denied*, 176 FERC ¶ 62,059 (July 29, 2021).

[64] As previously reported, the FERC issued a deficiency letter, on March 1, 2021, directing ISO-NE to provide additional information, including the following: (i) an example of a potential site for the reference unit (in or near New London County, CT) that is two miles from both a main natural gas transmission line and the point of interconnection to the electric grid; (ii) an estimate of NOx emissions limit and whether those limits affect the reference unit's revenues; and (iii) additional support for the assumption that the reference unit always runs on natural gas rather than oil in the dispatch model. The responses to the Deficiency Letter were due on or before March 31, 2021 and were filed by ISO-NE on March 30, 2021. ISO-NE's submission of the additional information re-set the 60-day deadline for FERC action on this filing.

[65] In its answer to the Deficiency Letter protests, ISO-NE stated that, assuming the FERC determines (as it has) that the reference unit requires on-site compression, the FERC should direct ISO-NE to include $8.75 million for that cost, that ISO-NE would account for on-site compression by adding $100,000 in annual operating and maintenance costs, reducing the seasonal capacity in the dispatch model by 5.5 MW (to account for load to run the compression equipment), and reducing the plant capacity available for participation in the Forward Capacity Market by 5.5 MW. Accordingly, ISO-NE stated that the resulting CONE, Net CONE, and PPR values would be $12.400/kW-month, $7.468/kW-month, and $9,337/MWh, respectively. *May 28 Order* at P 59.

[66] *ISO New England Inc.,* Docket No. ER21-787-002 (July 30, 2021) (unpublished letter order).

October 12, 2021. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **TOs *Order 676-I* Compliance Filing (ER21-2529)**

On July 27, 2021, the PTO AC, ISO-NE, Schedule 20A Service Providers, GMP, and VTransco filed revisions to ISO-NE Tariff Schedule 21-Common and Schedule 20A-Common in accordance with *Order 676-I*. The revisions include certain updated business practice standards (Version 003.2) adopted by the Wholesale Electric Quadrant ("WEQ") of the North American Energy Standards Board ("NAESB") and incorporated by reference in the FERC's regulations through *Order 676-I*. Comments on this filing were due on or before August 19, 2021; none were filed. National Grid filed a doc-less intervention on August 13, 2021. 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).

- **CSC Schedule 18 *Order 676-I* Compliance Filing (ER21-2509)**

On July 26, 2021, CSC and ISO-NE filed revisions to ISO-NE Tariff Schedule 18-Attachment Z in accordance with *Order 676-I*. The revisions include certain updated business practice standards (Version 003.2) adopted by NAESB's Wholesale Electric Quadrant and incorporated by reference in the FERC's regulations through *Order 676-I*. Comments on this filing were due on or before August 16, 2021; none were filed. National Grid and CSC filed doc-less interventions on August 13, 2021 and August 16, 2021, respectively. 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/NEPOOL *Order 676-I* Compliance Filing (ER21-941)**

On January 26, 2021, ISO-NE and NEPOOL, in response to *Order 676-I*, jointly filed changes to incorporate by reference in Schedule 24 of the OATT the latest version (Version 003.2) of certain Standards for Business Practices and Communication Protocols for Public Utilities adopted by NAESB's Wholesale Electric Quadrant. The Participants Committee unanimously supported the *Order 676-I* revisions at its May 7, 2020 meeting. Comments on this filing were due on or before February 16, 2021; none were filed. This matter remains 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

- **eTariff FAP Attachment 3 Corrections (ER21-2815)**

On September 1, 2021, ISO-NE filed corrections to its eTariff to reinstate in Attachment 3 to the FAP previously-accepted[67] text (footnote 1)[68] which was omitted in two subsequent filings.[69] Comments on this filing were due on or before September 22, 2021; none were filed. NEPOOL and Calpine filed doc-less interventions. 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).

[67] *See ISO New England Inc.*, Docket No. ER20-2145 (Sep. 2, 2020) (unpublished letter order).

[68] Footnote 1 reads: As used in this certification, a Certifying Entity's "independent risk management function" can include appropriate corporate persons or bodies that are independent of the Certifying Entity's trading functions, such as a risk management committee, a risk officer, a Certifying Entity's board or board committee, or a board or committee of the Certifying Entity's parent company."

[69] *See* Revisions Related to Disclosure Information Under the FAP, *ISO New England Inc. and the New England Power Pool Participants Comm.*, Docket No. ER21-816 (filed Jan. 6, 2021; corrected Feb. 23, 2021); Revisions to Obligations of Energy Efficiency Resources Under PFP, *ISO New England Inc.*, Docket No. ER21-943 (filed Jan. 26, 2021).

VI. Schedule 20/21/22/23 Changes

- **Schedule 20A-UI: Vitol Phase I/II HVDC-TF Service Agreement (ER21-2662)**

On August 12, 2021, United Illuminating ("UI") submitted a new Phase I/II HVDC-TF Service Agreement between itself and Vitol Inc. ("Vitol") under Schedule 20A-UI for 1 MW of firm service over the Phase I/II HVDC transmission facilities ("Phase I/II HVDC-TF"). A November 20, 2020 effective date was requested (the date on which monthly firm service began). Comments on this filing were due on or before September 2, 2021; none were filed. Vitol submitted a doc-less intervention. This matter is pending before the FERC. If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Schedule 20A-CMP: Vitol Phase I/II HVDC-TF Service Agreement (ER21-2661)**

Also on August 12, 2021, Central Maine Power ("CMP") similarly submitted a new Phase I/II HVDC-TF Service Agreement between itself and Vitol under Schedule 20A-CMP for 1 MW of firm service over the Phase I/II HVDC-TF. A November 20, 2020 effective date was requested (the date on which monthly firm service began). Comments on this filing were due on or before September 2, 2021; none were filed. Vitol submitted a doc-less intervention. This matter is pending before the FERC. If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

Still pending before the FERC is 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,*[70] and certified by Settlement Judge Dring[71] to the Commission.[72] 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 of the BHD OATT and $260,000 under the MPD OATT. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VII. NEPOOL Agreement/Participants Agreement Amendments

- **Waiver Agreement: PA Board Provisions (not docketed)**

On September 24, 2021, NEPOOL and ISO-NE submitted an informational filing advising the FERC of the waiver of sections 9.2.2 and 9.2.3(a) of the Participants Agreement (related to the size of the ISO Board and the term length of one new Board member) that was required to seat the four-person slate of candidates for election to the ISO Board of Directors. The Waiver Agreement was unanimously approved by the Participants Committee in balloting and approved by the ISO Board. This filing was not docketed and will not be noticed by the FERC for

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[70] *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.

[71] 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.

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

public comment. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@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*[73] *and 531-B*[74] 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	♦ National Grid	♦ United Illuminating
♦ Emera Maine	♦ NHT	♦ VTransco
♦ Eversource	♦ NSTAR	

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

- **Capital Projects Report - 2021 Q2 (ER21-2632)**

On October 1, 2021, the FERC accepted ISO-NE's Capital Projects Report and Unamortized Cost Schedule covering the second quarter ("Q2") of calendar year 2021 (the "Report").[75] As previously reported, Report highlights included the following new projects: (i) Forward Capacity Tracking System Infrastructure Conversion Part III ($3.15 million); (ii) FCM Cost Allocation & Accelerated Billing ($1.065 million); (iii) Enterprise Application Integration Phase II ($958,000); (iv) nGEM Hardware Phase I ($872,900); (v) Oracle 19c Upgrade ($653,000); (vi) Replacement of LMP Monitor ($383,800); (vii) Secure Lightweight Directory Access Protocol Channel Binding Adaptation ($294,400); (viii) Market Information System ("MIS") File Transfer Protocol ("FTP") Refresh ($155,000); Single Sign-on Technology Upgrade ($150,000). Projects with a significant changes (with amounts returned to the Emerging Work Fund following in parentheses) were (i) Communications Front End Energy Management Platform ("EMP") 3.2 Upgrade ($172,900); (ii) Sub-Accounts for FTR Market ($155,000); (iii) CIP Electronic Security Perimeter Redesign ($149,900); (iv) PI Historian for Short-term m Phasor Measurement Units ("PMU") Data Repository ($134,300); (v) FCM Qualification Enhancements ($120,000); and (vi) Capital Projects in Planning/Conceptual Design (e Human Resources Workflow & Document Management and ESI projects) ($299,200). The Report was accepted effective as of July 1, 2021, as requested. Unless the October 1 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

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

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

[75] *ISO New England Inc.*, Docket No. ER21-2632 (Oct. 1, 2021) (unpublished letter order).

- **Interconnection Study Metrics Processing Time Exceedance Report Q2 2021 (ER19-1951)**

On August 13, 2021, ISO-NE filed, as required,[76] public and confidential[77] versions of its Interconnection Study Metrics Processing Time Exceedance Report (the "Exceedance Report") for the second quarter of 2021 ("2021 Q2"). ISO-NE reported that one of the three 2021 Q2 ***Interconnection Feasibility Study ("IFS") reports*** delivered to Interconnection Customers were delivered later than the best efforts completion timeline.[78] In addition, three IFS Report that has not yet been completed has exceeded the 90-day completion expectation. The average time from ISO-NE's receipt of the executed IFS Agreement to delivery of the completed IFS report to the Interconnection Customer was 92.33 days (down from 115.4 in 2021 Q1). Four of the five ***System Impact Study ("SIS") reports*** delivered to Interconnection Customers were delivered later than the best efforts completion timeline of 270 days. The average time from ISO-NE's receipt of the executed SIS Agreement to delivery of the completed SIS report to the Interconnection Customer was 475 days (up from 434 in 2021 Q1). In addition, 12 SIS reports that are not yet completed have exceeded the 270-day completion expectation. Section 4 of the Report identified steps ISO-NE has identified to remedy issues and prevent future delays, including mitigating the impact of backlogs and initiating clustering, moving to earlier in the process certain Interconnection Customer data reviews, and enhanced information sharing and coordination efforts with Interconnecting TOs. This report was not noticed for public comment.

- **Reserve Market Compliance (31st) Semi-Annual Report (ER06-613)**

As directed by the original ASM II Order,[79] as modified,[80] ISO-NE submitted its 31st semi-annual reserve market compliance report on October 1, 2021. In the 31st report, ISO-NE stated that "is currently re-evaluating approaches to forward reserve products and will keep the Commission apprised of any plans with respect to a forward TMSR market in future reports in this docket." The October 1 report was not noticed for public comment. If there are questions on this matter, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com).

IX. Membership Filings

- **October 2021 Membership Filing (ER21-2985)**

On September 30, 2021, NEPOOL requested that the FERC accept (i) the memberships of CPV Valley, LLC [Related Person to CPV Towantic (Generation Sector)]; Generation Bridge Connecticut Holdings, LLC (Provisional Group Member) ("GB CT"); Generation Bridge M&M Holdings, LLC [Related Person to Generation Bridge CT [(Provisional Group Member)] ("GB M&M"); J.P. Morgan Ventures Energy Corporation (Supplier Sector) ("JPMVEC"); Oxford Energy Center, LLC (Provisional Group Member); Naugatuck Avenue Storage LLC [Related Person to Jupiter Power (Provisional Group Member)]; Norman Street ES LLC [Related Person to Jupiter Power (Provisional Group Member)]; and Westfield ESS LLC [Related Person to Jupiter Power (Provisional Group

[76] Under section 3.5.4 of ISO-NE's Large Generator Interconnection Procedures ("LGIP"), ISO-NE must submit an informational report to the FERC describing each study that exceeds its Interconnection Study deadline, the basis for the delay, and any steps taken to remedy the issue and prevent such delays in the future. The Exceedance Report must be filed within 45 days of the end of the calendar quarter, and ISO-NE must continue to report the information until it reports four consecutive quarters where the delayed amounts do not exceed 25 percent of all the studies conducted for any study type in two consecutive quarters.

[77] ISO-NE requested that the information contained in Section 3 of the un-redacted version of the Exceedance Report, which contains detailed information regarding ongoing Interconnection Studies and if released could harm or prejudice the competitive position of the Interconnection Customer, be treated as confidential under FERC regulations.

[78] 90 days from the Interconnection Customer's execution of the study agreement.

[79] *See NEPOOL and ISO New England Inc.*, 115 FERC ¶ 61,175 (2006) ("*ASM II Order*") (directing the ISO to provide updates on the implementation of a forward TMSR market), *reh'g denied* 117 FERC ¶ 61,106 (2006).

[80] *See NEPOOL and ISO New England Inc.*, 123 FERC ¶ 61,298 (2008) (continuing the semi-annual reporting requirement with respect to the consideration and implementation of a forward market for Ten-Minute Spinning Reserve ("TMSR")).

Member)]; and (ii) the name change of Rhode Island Bioenergy Facility, LLC (f/k/a Orbit Energy Rhode Island, LLC). Comments on this filing are due on or before October 21, 2021.

- **September 2021 Membership Filing (ER21-2802)**

On August 30, 2021, NEPOOL requested that the FERC accept (i) the memberships of Gravel Pit Solar, LLC [Related Person to DWW Solar II and Fusion Solar Center, LLC (AR Sector, Large RG Group Member)]; Tyr Energy (Supplier Sector); and Walden Renewables Development LLC (Provisional Member); and (ii) the termination of the Participant status of: Brookfield Energy Marketing Inc. [Related Person to Brookfield companies (Supplier Sector)]; and HIKO Energy and Perigee Energy [Related Persons to Spark Energy (Supplier Sector)]. Comments on this filing were due on or before September 21, 2021; none were filed. This filing is pending before the FERC.

- **August 2021 Membership Filing (ER21-2558)**

On September 27, 2021, the FERC accepted (i) the memberships of In Commodities US LLC (Supplier Sector); and Jupiter Power (Provisional Member); (ii) the termination of the Participant status of GenOn Energy Management and GenOn Canal; and (iii) the name change of Rivercrest Power-SOUTH, LLC (f/k/a BioUrja Power LLC).[81] Unless the September 27 order is challenged, this proceeding will be concluded.

- **Suspension Notice (not docketed)**

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

Date of Suspension/ FERC Notice	***Participant Name***	***Default Type***	***Date Reinstated***
Sep 15/17	Manchester Methane, LLC	Financial Assurance	Oct 5

Suspension notices are for the FERC's information only and are not docketed or noticed for public comment.

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

Questions concerning any of the ERO Reliability Standards or related rule-making proceedings or filings can be directed to Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Revised Reliability Standards: CIP-004-7, CIP-011-3 (RD21-6)**

On September 15, 2021, NERC filed for approval proposed changes to Reliability Standards CIP-004-7 (Cyber Security – Personnel & Training) and CIP-011-3 (Cyber Security – Information Protection). The changes clarify the protections required for the use of third-party solutions (e.g. cloud services, which depend less on the actual storage location of the information and more on file-level rights and permissions) for BES Cyber System Information ("BCSI"). NERC asked that the changes become effective (and the currently effective versions be retired) on the first day of the first calendar quarter that is 24 months following FERC approval. Comments on the changes are due on or before October 6, 2021.

- **Revised Reliability Standards (SOL Changes): FAC-003-5, 011-4, 014-3; IRO-008-3; PRC 002-3, 023-5, -026-2; and TOP-001-6 (RM21-19)**

On June 28, 2021, NERC filed for approval proposed changes to the following Reliability Standards related to establishing and communicating System Operating Limits ("SOLs", and together the "SOL Changes"):

[81] New England Power Pool Participants Committee, Docket No. ER21-2558 (Sep. 27, 2021) (unpublished letter order).

- FAC-011-4 (System Operating Limits Methodology for the Operations Horizon)
- FAC-014-3 (Establish and Communicate System Operating Limits)
- FAC-003-5 (Transmission Vegetation Management)
- IRO-008-3 (Reliability Coordinator Operational Analyses and Real-time Assessments)
- PRC-002-3 (Disturbance Monitoring and Reporting Requirements)
- PRC-023-5 (Transmission Relay Loadability)
- PRC-026-2 (Relay Performance During Stable Power Swings)
- TOP-001-6 (Transmission Operations)

NERC also requested the retirement of Reliability Standard FAC-010-3 (System Operating Limits Methodology for the Planning Horizon) and modifications to NERC's Glossary of Terms to revise the definition for System Operating Limit and to include "System Voltage Limit". The SOL Changes (NERC Project 2015-09) were developed in response to recommendations from a periodic review of the FAC-010, FAC-011, and FAC-014 Reliability Standards. NERC asked that revised Reliability Standards become effective (and the currently effective versions be retired) on the first day of the first calendar quarter that is 24 months following FERC approval. The SOL Changes have not yet been noticed for public comment.

- **NOI: Enhancements to CIP Standards (RM20-12)**

On June 18, 2020, the FERC issued a notice of inquiry ("NOI") seeking comments on certain potential enhancements to the currently-effective CIP Reliability Standards. In particular, the FERC asked for comments on whether the CIP Standards adequately address: (i) cybersecurity risks pertaining to data security, (ii) detection of anomalies and events, and (iii) mitigation of cybersecurity events. In addition, the FERC asked for comments on the potential risk of a coordinated cyberattack on geographically distributed targets and whether FERC action including potential modifications to the CIP Standards would be appropriate to address such risk.

Comments were filed by NERC, the ISO/RTO Council ("IRC"), APPA/LPPC, Canadian Electricity Assoc. ("CEA"), Cogentrix, EEI/EPSA, Forescout Technologies, MISO TOs, NJ BPU, NRECA, Reliable Energy Analytics, Southwestern Power Administration, SEIA, Siemen's Energy, Southern Companies, TAPS, U.S. Bureau of Reclamation, U.S Corp of Army Engineers, Western Area Power Administration ("WAPA"), Wolverine Power Supply Cooperative, XTec, and J. Applebaum, J. Christopher/T. Conway, and G. Cotter. No reply comments were filed. This matter is pending before the FERC.

- **NOI: Virtualization and Cloud Computing Services in BES Operations (RM20-8)**

On February 20, 2020, the FERC issued a NOI seeking comments on (i) the potential benefits and risks associated with the use of virtualization and cloud computing services in association with bulk electric system ("BES") operations; and (ii) whether the CIP Reliability Standards impede the voluntary adoption of virtualization or cloud computing services.[82] On March 25, 2020, Joint Associations[83] requested an extension of time to submit comments and reply comments. On April 2, the FERC granted Joint Associations' request and extended the deadline for initial comments on the NOI to July 1, 2020; the deadline for reply comments, July 31, 2020. Comments were filed by NERC, the IRC, Accenture, Amazon Web Services ("Amazon"), Bonneville, the Bureau of Reclamation, Barry Jones, Georgia System Operations, GridBright, Idaho Power, Microsoft, MISO, MISO Transmission Owners, Siemens Energy Management, Tri-State Generation and Transmission Association, VMware, Inc., AEE, American Association for Laboratory Accreditation ("A2LA"), APPA, Canadian Electricity Assoc., EEI, NRECA, and Waterfall Security Solutions. Reply comments were due on or before July 31, 2020, and were filed by AEE, Amazon and Microsoft.

[82] *Virtualization and Cloud Computing Services*, 170 FERC ¶ 61,110 (Feb. 20, 2020).

[83] "Joint Associations" are for purposes of this proceeding: EEI, APPA, NRECA, and LPPC.

In part in response to the comments filed, the FERC, in a December 17, 2020 order,[84] directed NERC to begin a formal process to assess, and to make an informational filing in a little over one year (January 1, 2022) that addresses, the feasibility of voluntarily conducting BES operations in the cloud in a secure manner, as well as the status and schedule for any plans to modify the standards.

- ***Order 873*** **- Retirement of Reliability Standard Requirements (Standards Efficiency Review) (RM19-17; RM19-16)**

On September 17, 2020, the FERC approved the retirement of the 18 Reliability Standard requirements through the retirement of four Reliability Standards and the modification of five Reliability Standards,[85] concluding that the 18 requirements "(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."[86] The FERC also approved the associated violation risk factors, violation severity levels, implementation plan, and effective dates proposed by NERC. Because it was not persuaded by NERC's justification for the retirement of FAC-008-4 requirement R8, the FERC remanded the retirement of requirements R7 and R8 to NERC for further consideration.[87]

The FERC left for another day its final action on the remaining 56 requirements for which the FERC proposed to approve retirement in the *Retirements NOPR*[88] (the "MOD A Reliability Standards"). The FERC intends to coordinate the effective dates for the retirement of the MOD A Reliability Standards with successor North American Energy Standards Board ("NAESB") business practice standards (v. 003.3) that include Modeling business practices, which were just accepted in *Order 676-J* (*see* Section XII below).

- **Rules of Procedure Changes (CMEP Risk-Based Approach Enhancements) (RR21-10)**

On September 29, 2021, NERC filed for approval changes to sections 400 (Compliance Monitoring and Enforcement) and 1500 (Confidential Information), Appendix 2 (Definitions) and Appendix 4C (Compliance Monitoring and Enforcement Program) of the NERC Rules of Procedure ("ROP"). The changes were proposed to further enhance the risk-based approach to the Compliance Monitoring and Enforcement Program ("CMEP") whereby registered entities and the ERO Enterprise focus on the greatest risks to the reliability and security of the Bulk Power System ("BPS"). Comments on this filing are due on or before October 6, 2021.

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[84] *Virtualization and Cloud Computing Services*, 173 FERC ¶ 61,243 (Dec. 17, 2020) ("*Order Directing Jan 2022 Info. Filing*").

[85] *Elec. Rel. Org. Proposal to Retire Reqs. in Rel. Standards Under the NERC Standards Efficiency Review*, Order No. 873, 172 FERC ¶ 61,225 (Sep. 17, 2020) ("*Order 873*"). The four Reliability Standards being eliminated in their entirety are 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-020-0 (Providing Interruptible Demands and Direct Control Load Management Data to System Operations and Reliability Coordinators). The five modified Reliability Standards are INT-006-5 (Evaluation of Interchange Transactions), INT-009-3 (Implementation of Interchange) and PRC-004-6 (Protection System Misoperation Identification and Correction), IRO-002-7 (Reliability Coordination—Monitoring and Analysis), TOP-001-5 (Transmission Operations).

[86] *Order 873* at P 2.

[87] *Order 873* at P 5. Pursuant to FPA section 215(d)(4), if the FERC disapproves a modification to a Reliability Standard in whole or in part, it must remand the entire Reliability Standard to NERC for further consideration. Accordingly, although it was satisfied here with the justification for the retirement of R7, the FERC was required to remand both R7 and R8 so that its concerns with the retirement of Requirement R8 could be addressed.

[88] *Electric Reliability Organization Proposal to Retire Requirements in Rel. Standards Under the NERC Standards Efficiency Review*, 170 FERC ¶ 61,032 (Jan. 23, 2020) ("*Retirements NOPR*") (proposing to approve the retirement of 74 of 77 Reliability Standard requirements requested to be retired by NERC in these two dockets in connection with the first phase of work under NERC's Standards Efficiency Review, an initiative begun in 2017 that 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). As previously reported, NERC withdrew its proposed changes to VAR-001-6 on May 14, 2020, reducing to 76 the number of requirements proposed to be retired.

- **2022 NERC/NPCC Business Plans and Budgets (RR21-9)**

On August 24, 2021, NERC submitted its proposed Business Plan and Budget, as well as the Business Plans and Budgets for the Regional Entities, including NPCC, for 2022. FERC regulations[89] require NERC to file its proposed annual budget for statutory and non-statutory activities 130 days before the beginning of its fiscal year (January 1), as well as the annual budget of each Regional Entity for their statutory and non-statutory activities, including complete business plans, organization charts, and explanations of the proposed collection of all dues, fees and charges and the proposed expenditure of funds collected. NERC reports that its proposed 2022 funding requirement represents an overall increase of approximately 6.2% over NERC's 2021 funding requirement. The NPCC U.S. allocation of NERC's net funding requirement is $9.44 million. NPCC has requested $17.5 million in statutory funding (a U.S. assessment per kWh (2020 NEL) of $0.0000540) and $1 million for non-statutory functions. Comments on this filing were due on or before September 14, 2021; none were filed.

On September 29, 2021, NERC amended its August 24 filing to include additional Fixed Asset expenditures NERC expects to incur in 2022 in connection with its anticipated move to a new headquarters office location in the Atlanta, Georgia, area ("Budget Amendment"). The Budget Amendment does not provide for any increase from the Original Budget in NERC's 2022 statutory assessments, nor is there any change proposed to any Regional Entity's 2022 Business Plan and Budget. Comments on the Budget Amendment are due on or before October 12, 2021.

- **Rules of Procedure Changes (Reliability Standards Development Revisions) (RR21-8)**

On August 18, 2021, NERC filed for approval revisions to sections 300 (Reliability Standards Development), Appendix 3B (Procedure for Election of Members of the Standards Committee) and Appendix 3D (Development of Registered Ballot Body Criteria) of the NERC Rules of Procedure ("ROP"), which are designed to update language, staff titles, and processes; remove unnecessary or duplicative obligations; and clarify roles and responsibilities related to the development of Reliability Standards (the "Reliability Standards Development ROP Revisions"). Comments on this filing were due on or before September 8, 2021; none were filed. This matter is pending before the FERC.

- **Report of Comparisons of 2020 Budgeted to Actual Costs for NERC and the Regional Entities (RR21-5)**

On June 1, 2021, NERC filed comparisons of actual to budgeted costs for 2020 for NERC and the six Regional Entities operating in 2020, including NPCC. The Report includes comparisons of actual funding received and costs incurred, with explanations of significant actual cost-to-budget variances, audited financial statements, and tables showing metrics concerning NERC and Regional Entity administrative costs in their 2020 budgets and actual results. Comments on this filing were due on or before June 22, 2021; none were filed. This matter is pending before the FERC.

- **SolarWinds and Related Supply Chain Compromise White Paper (not docketed)**

On July 7, 2021, FERC staff and E-ISAC released a joint white paper emphasizing the need for continued vigilance by the electricity industry related to supply chain compromises and incidents and recommending specific cybersecurity mitigation actions to better ensure the security of the bulk-power system ("BPS"). View the Report here.

- **FERC/NERC Joint Report on Real Time Assessments (not docketed)**

On July 8, 2021, FERC Staff, together with staff from NERC and its regional entities issued a report outlining recommendations for real-time assessments of grid operating conditions.[90] The report concluded that

[89] 18 CFR § 39.4(b) (2014).

[90] Real-time assessments evaluate system conditions using real-time data to measure existing and potential operating conditions to ensure continued reliable operation of the bulk electric system. The joint staff review focuses on strategies and techniques used by reliability coordinators and transmission operators to perform these assessments following a loss or degradation of data or tools used to

system operators are prepared to manage limited impairments of their primary assessment tools or data through system redundancy and redundant data sources. However, infrequent events involving significant real-time data loss or the failure of primary analysis tools lasting more than two hours require the development of alternative data sources, tools, and analyses work to mitigate the potential loss of visibility and control resulting from the impairment of their primary tools. The report addressed the following seven technical areas related to real-time assessments, including observations, conclusions, and recommendations for each: (i) Real-time Assessment Tools Under Normal Operating Conditions; (ii) Real-time Data and Data Quality; (iii) Real-time Data Loss Management; (iv) Alternative Real-time Assessment and Study Tools; (v) Model Management; (vi) Control Center Hardware Configuration; and (vii) Major System Upgrades/Vendor Changes. View the Report here.

XI. Misc. - of Regional Interest

- **203 Application: PSEG/Generation Bridge II (ArcLight) (EC21-125)**

On September 2, 2021, PSEG Project Companies[91] and Generation Bridge II, LLC ("Purchaser") requested authorization for a transaction pursuant to which 100% of the membership interests in the PSEG Project Companies will be sold to Generation Bridge II, a wholly-owned, indirect subsidiary of ArcLight Fund VII, which is itself affiliated with Great River Hydro. On September 28, 2021, applicants submitted revised pages of an affidavit included in the original filing to correct statements regarding the ownership of certain assets. Applicants stated that the correction did not affect the analysis or conclusions presented in the original filing. Comments on the correction are due on or before November 29, 2021. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Valcour Wind Energy/AES (EC21-114)**

On August 13, 2021, Valcour Wind Energy, LLC ("Valcour") and AES Corporation, among others, requested authorization for a transaction pursuant to which Valcour will become, ultimately, a Related Person of AES. Consummation of this transaction will make Valcour Wind Energy and AES Distributed Energy, Inc. Related Persons. Comments on this filing were due on or before September 3, 2021; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Covanta/EQT (EC21-113)**

On August 11, 2021, Covanta Holding Corporation, on behalf of and together with its public utility subsidiaries, including NEPOOL member Covanta Energy Marketing, LLC ("Covanta"), requested authorization for a transaction pursuant to which Covanta will become a wholly-owned subsidiary Covert Intermediate, Inc., itself an indirectly, wholly-owned affiliate of EQT AB ("EQT"). Consummation of this and the Cypress Creek Holdings transaction summarized just below, will make Covanta and Cypress Creek Renewables Related Persons. Comments on this filing were due on or before September 1, 2021; none were filed. Doc-less interventions were filed by the PJM IMM and Covert Mergeco, Inc. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Cypress Creek/EQT (EC21-108)**

On October 1, 2021, the FERC authorized a transaction pursuant to which Cypress Creek Renewables, LLC, among others, will become a wholly-owned subsidiary Catalyst AcquisitionCo, Inc. ("Catalyst"), itself an indirectly, wholly-owned affiliate of EQT.[92] Consummation of this and the Covanta transaction summarized just above, will

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maintain situational awareness. The review included on-site discussions with representatives of nine participating reliability coordinators and transmission operators.

[91] The "PSEG Project Companies" are: PSEG New Haven LLC ("PSEG New Haven"), PSEG Power Connecticut LLC ("PSEG Power CT"), PSEG Power New York LLC ("PSEG Power NY").

[92] *Cypress Creek Holdings, LLC*, 177 FERC ¶ 62,003 (Oct. 1, 2021).

make Cypress Creek Renewables and Covanta Energy Marketing Related Persons. Unless the October 1 order is challenged, this proceeding will be concluded. Also, pursuant to the October 1 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. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: PPL/Narragansett (EC21-87)**

On September 23, 2021, the FERC authorized a transaction pursuant to which a wholly-owned subsidiary of PPL Corporation will acquire 100% of the outstanding shares of common stock of The Narragansett Electric Company ("Narragansett").[93] This transaction is expected to close in the fourth quarter of 2021. Pursuant to the September 23 order, notice must be filed within 10 days of consummation of the transaction. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Seneca/Rice et al. (EC21-84)**

On September 24, 2021, Archaea Energy, LLC ("Archaea") provided notice that the FERC-authorized transaction,[94] pursuant to which the ultimate upstream ownership of Seneca Energy II ("Seneca"), among others, will change to include a publicly listed company (Rice Acquisition Corp. ("Rice")) and both Aria Energy LLC ("Aria"), which is wholly-owned by funds managed by Ares Management Corporation ("Ares Management"), and Archaea, was consummated on September 15, 2021. As previously summarized, Aria affiliates now hold approximately 20% of the outstanding voting shares; Archaea and its members, 29%; Rice and its shareholders, the remaining shares. Seneca remains, for the time being, a Related Person to Generation Sector member Kleen Energy. Reporting on this matter is concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: NRG/Generation Bridge (ArcLight) (EC21-74)**

On August 18, 2021, the FERC authorized a transaction pursuant to which 100% of the membership interest in certain NRG Project Companies[95] will be sold to Generation Bridge Acquisition, LLC ("Purchaser"), a wholly-owned, indirect subsidiary of ArcLight Fund VI, which is itself affiliated with Great River Hydro.[96] Pursuant to the August 18 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. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Exelon Generation (EC21-57)**

On August 24, 2021, the FERC authorized a "spin" transaction in which, after completion of an internal reorganization, the ownership of the public utility subsidiaries ("ExGen Utility Subsidiaries") of Exelon Generation Company, LLC ("ExGen") intermediate holding company owner, HoldCo, will be distributed to the shareholders of Applicants' current ultimate upstream owner, Exelon Corporation (the "Transaction").[97] Following the Transaction, Exelon Corporation and its remaining subsidiaries will retain no interest in or affiliation with ExGen or the ExGen Utility Subsidiaries; Exelon Corporation and HoldCo will be separate publicly-traded companies. Notice must be filed within 10 days of consummation of the transaction, which as of the date of this Report has not yet occurred. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

[93] *PPL Corp. and The Narragansett Elec. Co.*, 176 FERC ¶ 61,175 (Sep. 23, 2021).

[94] *Seneca Energy, II LLC et al.*, 175 FERC ¶ 62,170 (June 14, 2021).

[95] The New England "NRG Project Companies" are Connecticut Jet Power LLC ("Connecticut Jet"), Devon Power LLC ("Devon"), Middletown Power LLC ("Middletown"), and Montville Power LLC ("Montville").

[96] *Arthur Kill Power LLC et al.*, 176 FERC ¶ 62,086 (Aug. 18, 2021).

[97] *Exelon Generation Co., LLC*, 176 FERC ¶ 61,121 (Aug. 24, 2021).

- **CL&P/EIP E&P Agreement (ER21-2880)**

On September 13, 2021, CL&P filed an Engineering, Design & Procurement Agreement ("E&P Agreement") between itself and EIP Investments, LLC ("EIP"). The E&P Agreement (designated as Service Agreement IA-ESCLP-009) provides the terms and conditions under which CL&P will undertake certain engineering and design services for the upgrades identified in the System Impact Study for the interconnection to CL&P's 69 kV transmission line connected to CL&P's Black Rock substation located in New Britain, Connecticut. A September 14, 2021 effective date was requested. Comments on this filing were due on or before October 5, 2021; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **IA Termination: CL&P / Sterling Property (ER21-2860)**

On September 9, 2021, CL&P filed a notice of termination of a 2002 Interconnection Agreement ("IA") governing interconnection service to a since decommissioned 26 MW waste-tire fueled generator located in Sterling, Connecticut (the "Facility").[98] The IA was accepted in Docket No. ER03-434,[99] and according to CL&P can be terminated under Section 2 of the IA because the Facility has been decommissioned. A November 8, 2021 effective date was requested. Comments on the notice were due on or before September 30, 2021. On September 30, Sterling Property, LLC ("Sterling"), owner of the Facility, filed a protest, asserting that the facility has not been decommissioned, and the regulatory proceeding before the Connecticut Department of Energy and the Environment ("CT DEEP") referenced in CL&P's termination notice, remains open and ongoing. Sterling stated that the FERC should "decline to exercise primary jurisdiction over this matter, given that the parties' dispute involves a factual dispute regarding a state regulatory proceeding, and further involves issues of contract interpretation that do not require the [FERC]'s specialized expertise to resolve or implicate the [FERC]'s regulatory responsibilities". Brookfield submitted a doc-less intervention. This matter is now pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **TSAs: Third Amendments to NECEC Transmission TSAs (ER21-2738 et al.)**

On August 23, 2021, NECEC Transmission filed executed third amendments to 7 of its previously-filed and accepted, cost-based transmission service agreements ("TSAs") with the participants that will fund the construction, operation and maintenance of the New England Clean Energy Connect Project.[100] The amendments are intended to (i) clarify the scope of the NECEC Project, specifically the Network Upgrades needed to interconnect the project to the New England Transmission System, based on the results of the applicable ISO-NE system impact studies; and (ii) allow NECEC Transmission to certify achievement of certain critical milestones related to construction authorizations and other approvals from governmental organizations and ISO-NE, based on the clarified scope. An August 24, 2021 effective date was requested. Comments on the third amendments were due on or before September 13, 2021; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Seabrook/NECEC E&P Agreement (ER21-2719)**

On October 4, 2021, the FERC accepted an Engineering & Procurement Agreement ("E&P Agreement") between NextEra Energy Seabrook, LLC ("Seabrook") and NECEC Transmission, LLC.[101] As previously reported,

[98] The IA originally was between CL&P and Exeter Energy Limited Partnership ("Exeter"). The IA was assumed by Exeter's successor-in-interest, EmpireCo Limited Partnership ("EmpireCo"), who later assigned the IA to Sterling Property, LLC.

[99] *Northeast Utils. Serv. Co.*, Docket No. ER03-434 (Mar. 17, 2003) (unpublished letter order).

[100] The third amendments to the 7 TSAs were separately docketed as follows: Eversource (ER21-2738); National Grid (ER21-2739); Unitil (ER21-2742); HQUS/Eversource (ER21-2743); HQUS/National Grid (ER21-2744); HQUS/Unitil (ER21-2745); and HQUS Additional (ER21-2747).

[101] *NextEra Energy Seabrook, LLC*, Docket No. ER21-2719 (Oct. 4, 2021) (unpublished letter order).

the E&P Agreement (designated as Seabrook Rate Schedule No. 2) provides the terms and conditions "concerning the engineering and procurement of long lead-time items" associated with work to be engaged in by Seabrook at NECEC's request "for the design, engineering, planning, permitting, and procurement of material and equipment" necessary to address the Significant Adverse Impact on Seabrook. Seabrook reported that all of the terms and conditions of the E&P Agreement had been mutually agreed upon. The E&P Agreement was accepted effective August 20, 2021, as requested. Unless the October 4 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).

- **ISA: NSTAR/Servistar (ER21-2696)**

On August 16, 2021, NSTAR filed an interconnection study agreement ("ISA") between itself and Servistar LLC ("Servistar"). Servistar is proposing to interconnect a 150 MW data center facility to Eversource's 1293 and 1302 115 kV transmission lines (ISO-NE queue position #1140). The ISA sets forth the terms and conditions under which NSTAR will study the feasibility of the project's interconnection ahead of the commencement of the ISO-NE study to give a preliminary review of possible adverse impacts to the system which the project will be responsible to mitigate. Comments on the ISA were due on or before September 7, 2021; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement: NSTAR/Medway Grid II (ER21-2684)**

On August 16, 2021, NSTAR filed a second D&E Agreement between itself and Medway Grid, LLC ("Medway"). The second Medway D&E Agreement sets forth the terms and conditions under which NSTAR will undertake certain preliminary design and engineering activities related to the upgrades identified in the System Impact Study for queue position #844, Medway's request to interconnect to NSTAR's 3445 kV West Medway Substation. Comments on the NSTAR/Medway Grid II D&E Agreement were due on or before September 7, 2021; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **LGIA: National Grid / New England Wind (Hoosac) (ER21-2548)**

On September 24, 2021, the FERC accepted a First Revised LGIA between National Grid, ISO-NE ("Filing Parties") and New England Wind.[102] The First Revised LGIA includes details regarding the Direct Assignment Facilities charge omitted from the original LGIA and updates the Capacity Network Resource Capability ("CNRC") of the 28.5 MW Hoosac wind farm. Going forward, the Filing Parties will report the conforming First Revised LGIA in their respective Electric Quarterly Reports. The First Revised LGIA was accepted effective as of March 19, 2021, as requested. Unless the September 24 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Versant Power MPD OATT *Order 676-I* Compliance Filing (ER21-2498)**

On July 23, 2021, Versant Power filed proposed revisions to Section 4 of the Versant Power Open Access Transmission Tariff For Maine Public District (the "MPD OATT") to incorporate by reference certain of the revisions required by *Order 676-I* and requested waiver of certain of those standards that are not applicable to MPD and/or the MPD OATT. Comments on this filing were due on or before August 13, 2021; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Versant Waiver Request: Unreserved Transmission Use Penalty Policy (ER21-2447)**

On September 27, 2021, the FERC dismissed Versant Power's request for a limited waiver of the application of its posted policy statement regarding penalties for unreserved transmission use that was in

[102] *ISO New England Inc. and New England Power Co.*, Docket No. ER21-2548 (Sep. 24, 2021) (unpublished letter order).

effect from January through March 2021 ("Prior Policy") to Black Bear SO, LLC and Black Bear Hydro Partners, LLC (jointly, "Black Bear").[103] The FERC dismissed the waiver request because Versant Power's Prior Policy was a business rule that was not part of the tariff on file with the FERC.[104] In addition, the FERC stated that "calculating Black Bear's unreserved-use penalties pursuant to the Current Policy is consistent with section 9.3 of Schedule 21-VP, which is the filed rate that determines the penalty cap."[105] Unless the September 27 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).

- **Amended and Restated IRH Support and Use Agreements eTariff Compliance Filings (ER21-2163 et al.)**

On September 16, 2021, the FERC accepted[106] the remaining pending compliance filing with revised tariff records in eTariff format reflecting the FERC's approval of the settlement[107] that amended and restated four Support Agreements and an Agreement with Respect to Use of Québec Interconnection ("Use Agreement").[108] Reporting on this matter is now concluded. If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Orders 864/864-A* (Public Util. Trans. ADIT Rate Changes): *New England Compliance Filings* (various)**

In accordance with *Order 864*[109] and *Order 864-A,*[110] and extensions of time granted, New England's public utilities with transmission have submitted their *Order 864* compliance filings, with the specific dockets and filing dates identified in the following table (all remain pending):

Date Filed	Docket	Transmission Provider	Date Accepted
Mar 11, 2021	ER21-1325	NHT	pending
Mar 8, 2021	ER21-1295	Eversource (CL&P, PSNH, NSTAR)	pending
Feb 16, 2021	ER21-1154	Fitchburg Gas & Electric ("FG&E")	pending
Oct 30, 2020 Apr 16, 2021	ER21-311 ER21-1694	Green Mountain Power	pending pending
Aug 5, 2020	ER20-2614	New England Power AC Support Agreement	pending
Aug 5, 2020	ER20-2610	CL&P	pending

[103] *Versant Power*, 176 FERC ¶ 61,210 (Sep. 27, 2021).

[104] *Id.* at P 16.

[105] *Id.*

[106] Vermont Elec. Transmission Co., Docket No. ER21-2158 (

Issued: September 16, 2021

[107] *New England Hydro-Transmission Electric Company, Inc. et al.*, 175 FERC ¶ 61,140 (May 20, 2021).

[108] The Support Agreements are separate contracts between the IRH and each of the Asset Owners under which the IRH agree to financially support the elements of the Phase I/II HVDC-TF owned by each Asset Owner in exchange for rights to use the transmission capacity of the Phase I/II HVDC-TF to transmit power to and from the HQ system ("Use Rights"). The Use Agreement is a contract among the IRH that provides the rules for the exercise of the Use Rights, for making the Use Rights available to others, and for the collective management of those individual contractual rights through the IRH Management Committee. The term of the Support Agreements (and thereby the Use Agreement) was extended for another 20 years, until October 31, 2040.

[109] *Public Util. Trans. Rate Changes to Address Accumulated Deferred Income Taxes*, Order No. 864, 169 FERC ¶ 61,139 (Nov. 21, 2019), *reh'g denied and clarification granted in part,* 171 FERC ¶ 61,033 (Apr. 16, 2020) ("*Order 864*"). *Order 864* requires 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 information.

[110] *Public Util. Trans. Rate Changes to Address Accumulated Deferred Income Taxes*, 171 FERC ¶ 61,033, Order No. 864-A (Apr. 16, 2020) ("*Order 864-A*").

Aug 5, 2020	ER20-2609 ER21-1650	NSTAR	pending pending
Aug 5, 2020	ER20-2608	PSNH	pending
Aug 4, 2020	ER20-2607	NEP – Seabrook Transmission Support Agreement	pending
Jul 31, 2020	ER20-2594 ER21-1709	VTransco	pending pending
Jul 30, 2020	ER20-2572 ER21-1130	New England TOs	pending
Jul 30, 2020	ER20-2553	NEP – LSA with MECO/Nantucket	pending
Jul 30, 2020	ER20-2551	New England Power	pending
Jul 15, 2020	ER20-2429 ER21-1702	CMP	pending pending
Jun 29, 2020	ER20-2219	New England Power	pending
Jun 23, 2020 Mar 22, 2021	ER20-2133 -001	Versant Power	pending
May 18, 2020 Jan 7, 2021	ER20-1839	VETCO	pending
Feb 26, 2020 Dec 11, 2020	ER20-1089	New England Elec. Trans. Corp.	pending
Feb 26, 2020 Dec 11, 2020	ER20-1088	New England Hydro Trans. Elec. Co.	pending
Feb 26, 2020 Dec 11, 2020	ER20-1087	New England Hydro Trans. Corp.	pending

Since the last Report, *Order 864*-related activity included:

♦ ***ER20-2429 (CMP)***. On September 15, 2021, the FERC issued a second deficiency letter. CMP responses were initially due on or before September 30, 2021. However, following a September 29, 2021 CMP request for an extension of time, CMP's responses to the second deficiency letter are now due October 22, 2021.

XII. Misc. - Administrative & Rulemaking Proceedings

- **Joint Federal-State Task Force on Electric Transmission (AD21-15)**

On June 17, 2021,the FERC established a Joint Federal-State Task Force on Electric Transmission ("Transmission Task Force").[111] The Transmission Task Force will be comprised of all FERC Commissioners as well as representatives from 10 state commissions (two from each NARUC region). State commission representatives will serve one-year terms from the date of appointment by FERC and in no event will serve on the Task Force for more than three consecutive terms. The Transmission Task Force will convene multiple formal meetings annually, with FERC issuing orders fixing the time and place and agenda for each meeting, and will be open to the public for listening and observing and on the record. The Transmission Task Force will focus on "topics related to efficiently and fairly planning and paying for transmission, including transmission to facilitate generator interconnection, that provides benefits from a federal and state perspective."[112] On July 19, 2021, NARUC nominated the 10 state

[111] *Joint Federal-State Task Force on Electric Transmission*, 175 FERC ¶ 61,224 (June 18, 2021).

[112] Topics that the Task Force may consider include: (i) identifying barriers that inhibit planning and development of optimal transmission necessary to achieve federal and state policy goals, as well as potential solutions to those barriers; (ii) exploring potential bases for one or more states to use FERC-jurisdictional transmission planning processes to advance their policy goals, including multi-state goals; (iii) exploring opportunities for states to voluntarily coordinate in order to identify, plan, and develop regional transmission solutions; (iv) reviewing FERC rules and regulations regarding planning and cost allocation of transmission projects and potentially identifying recommendations for reforms; (v) examining barriers to the efficient and expeditious interconnection of new resources through the FERC-jurisdictional interconnection processes, as well as potential solutions to those barriers; and (vi) discussing mechanisms to ensure that

commissioners to the Transmission Task Force, including New England Commissioners Riley Allen (VT PUC) and Matt Nelson (Chair, MA DPU).

On August 30, 2021, the FERC issued an order listing the 10 state commissioner members (confirming the nominations of Commissioner Allen and Chairman Nelson), announcing the first public meeting of the Task Force (to be held Wednesday, November 10, 2021, from approximately 1:00 pm to 6:00 p.m., in Louisville, Kentucky, in conjunction with the NARUC meeting scheduled to be held there), and inviting agenda topics (all interested persons, including all state commissions, were invited to file comments in this docket on agenda topics for the first public meeting on or before September 10, 2021).[113] Comments on the agenda were filed by AEP, APPA, the Environmental Law and Policy Center and National Audubon Society, ITC, NYU's Institute for Policy Integrity, Shell, Southern Company Services, Wires.

- **Climate Change, Extreme Weather, and Electric Sys. Reliability: Jun 1-2 Technical Conference (AD21-13)**

On June 1-2, 2021, FERC staff convened a technical conference to discuss issues surrounding the threat to electric system reliability posed by climate change and extreme weather events. This technical conference addressed (i) concerns that, because extreme weather events are increasing in frequency, intensity, geographic expanse, and duration, the number and severity of weather-induced events in the electric power industry may also increase; and (ii) specific challenges posed to electric system reliability by climate change and extreme weather, which may vary by region. The FERC seeks to understand the near, medium and long-term challenges facing the regions of the country; how decision makers in the regions are evaluating and addressing those challenges; and whether further FERC action is needed to help achieve an electric system that can withstand, respond to, and recover from extreme weather events. Pre-technical conference comments were due on or before April 15, 2021 and were filed by, among others, ISO-NE, AEE, Dominion, EDF, Eversource, Exelon, LS Power, National Grid, PSEG, Vistra, APPA, Capital Power, EEI, NARUC, NEI, NERC, NRECA, and the R Street Institute. Speaker materials were posted in eLibrary on June 3, 2021; transcripts of the June 1-2 days, July 22, 2021.

On August 11, 2021, the FERC issued a notice inviting post-technical conference comments. Comments could address the questions raised in the notice, as well as any other issues raised during the technical conference or identified in the Supplemental Notices of Technical Conference issued March 15 and May 21, 2021. Comments were due on or before September 27, 2021 and were filed by: CAISO; MISO; NYISO; PJM; AEP; City of New Orleans; City of New York; Columbia Law School's Sabin Center for Climate Change Law; EDF and Sabin Center for Climate Change Law; EEI; EPSA; Eversource; Exelon, Jupiter Intelligence; Louisville Gas and Electric Company and Kentucky Utilities Company; MI PSC; NRDC, Sierra Club, Sustainable FERC Project, and UCS; Old Dominion Electric Cooperative ("ODEC"); NERC; and C. Wright. This matter is pending before the FERC.

- **Electrification and the Grid of the Future: Apr 29 Technical Conference (AD21-12)**

On April 29, 2021, the FERC convened a Commissioner-led technical conference to discuss electrification—the shift from non-electric to electric sources of energy at the point of final consumption (e.g., to fuel vehicles, heat and cool homes and businesses, and provide process heat at industrial facilities). The purpose of the technical conference was to "initiate a dialog between Commissioners and stakeholders on how to prepare for an increasingly electrified future." Panel discussions addressed (1) projections, drivers, and risks of electrification; (2) infrastructure requirements of electrification (the extent to which electrification may influence or necessitate additional transmission and generation infrastructure); (3) transmission and distribution system services provided by flexible demand (how newly electrified sources of energy demand (e.g., electric vehicles, smart thermostats, etc.) could provide grid services and enhance reliability); and (4) the role of local, state, and federal coordination

transmission investment is cost effective, including approaches to enhance transparency and improve oversight of transmission investment including, potentially, through enhanced federal-state coordination.

[113] *Joint Federal-State Task Force on Electric Transmission*, 176 FERC ¶ 61,131 (Aug. 30, 2021).

as electrification advances. On May 17, the FERC issued a notice inviting the submission of post-technical conference comments, on or before July 1, 20201, addressing issues raised during the technical conference and/or identified in the April 14, 2021 Supplemental Notice of Technical Conference. Nearly 20 sets of comments were filed, including comments by: AGA, CAISO, EEI, IL ICC, MISO, MISO TOs, Organization of MISO States, NEMA, NRECA, Chargepoint, CTC Global, Electrify America, Entergy, Environmental Defense Fund, ITC Holdings, Prairie Power, National Grid, and R Street Institute. Since the last Report, the FERC posted to eLibrary a transcript of the April 29 technical conference. This matter remains pending before the FERC.

- **Reliability Technical Conference (Sep 30) (AD21-11)**

On September 30, 2021, the FERC convened its annual Commissioner-led technical conference to discuss policy issues related to the reliability of the Bulk-Power System ("BPS"). Panel discussions addressed: (1) BPS reliability and security (current state, challenges and initiatives); (2) extreme weather, risks and challenges); (3) managing cyber risks in the electric power sector; and (4) maintaining electric reliability with changing resource mix. A detailed final agenda, identifying the presenters and panelists, is available here. Speaker materials have been posted to eLibrary.

- **Modernizing Electricity Market Design - Resource Adequacy (AD21-10)**

March 23 Tech Conf (PJM). The FERC convened a Commissioner-led technical conference was on March 23, 2021 to provide input to the Commission on resource adequacy in the evolving electricity sector. Speaker materials from the March 23 technical conference have been posted to eLibrary. On March 29, Ohio PUC Commission Dan Conway submitted written comments. On April 5, the FERC issued a notice inviting post-technical conference comments on specific PJM-specific questions. Initial comments were due on or before April 26, 2021; reply comments must be submitted on or before May 10, 2021. More than 45 sets of comments were filed, including by: AEE, Calpine, Cogentrix, Dominion, Exelon, FirstLight, LS Power, NESCOE, NEPGA, NRG, PSEG, Shell, Vistra, CT DEEP, EEI, EPSA, and NRECA/APPA, some of which addressed issues to be discussed in the May 25 New England technical conference (identified immediately below). On May 10, 2021, reply comments were filed by the American Clean Power Association ("ACPA"), AEP, EPSA, Exelon, Joint Consumer Advocates, LS Power, Old Dominion Electric Cooperative ("ODEC"), PJM Power Providers ("P3"), Public Interest Organizations ("PIOs"), and the Retail Electric Supply Association ("RESA").

May 25 Tech Conf (New England). On May 25, 2021, the FERC held a Commissioner-led technical conference regarding the wholesale markets administered by ISO New England Inc. Supplemental notices of the technical conference were issued on May 3 and May 17. The May 17 supplemental notice identified panelists and topics/questions for discussion for the technical conference. Panel discussions included: (1) a Commissioner-led discussion of the relationship between state policies and the New England Markets; (2) a Staff-led discussion of short-term options and complementary potential market changes to accommodate state policies in New England; and (3) a Staff-led discussion of long-term options and centralized procurement of clean energy.

Post (New England) Tech Conf Comments. On June 4, 2021, the FERC issued a notice inviting post-technical conference comments on the issues raised during the technical conference, including the questions listed in the May 17, 2021 supplemental notice. Post-technical conference comments were due on or before ***July 19, 2021*** and were filed by: AEE, Calpine, CT Parties, Dominion, Eversource, MMWEC, NESCOE, NEPGA, NextEra, NRG, Public Interest Orgs, Vistra, AEMA, EPSA, RENEW.

- **Modernizing Electricity Market Design - Energy and Ancillary Service Markets (AD21-10)**

On September 14, 2021, the FERC held the first of two staff-led technical conferences addressing ISO/RTO energy and ancillary services markets. As previously reported, the technical conferences will discuss potential energy and ancillary services market reforms, such as market reforms to increase operational flexibility, that may be needed as the resource fleet and load profiles change over time. The second technical conference will be held on Tuesday, October 12, 2021 (9-5 p.m.).

Tech Conf I (Sep 14). The FERC convened the first technical conference on September 14, 2021, a full-day technical conference discussing potential energy and ancillary services market reforms, such as market reforms to increase operational flexibility, that may be needed as the resource fleet and load profiles change over time. In a supplemental notice issued on August 17, 2021, the FERC identified the following four panels and the topics and questions to be discussed: (1) Understanding the Need for Additional Operational Flexibility in RTO/ISO Energy and Ancillary Services Markets; (2) Revising Existing Operating Reserve Demand Curves ("ORDCs") to Address Operational Flexibility Needs in RTOs/ISOs; (3) Creating New Products to Address Operational Flexibility Needs in RTOs/ISOs; and (4) Market Design Issues and Tradeoffs to Consider in Reforms to Increase Operational Flexibility in RTO/ISO Energy and Ancillary Services Markets. Speakers were identified in a second supplemental notice issued on September 3, 2021.

Tech Conf II (Oct 12). The FERC will also convene remotely on October 12, 2021 a second full-day technical conference to discuss potential energy and ancillary services market reforms. On October 1, 2021, the FERC issued a supplemental notice of the October 12 technical conference, identifying the following four panels and topics to be discussed: (1) Incenting Resources to Reflect Their Full Operational Flexibility in Energy and Ancillary Services Offers; (2) Maximizing the Operational Flexibility Available from New and Emerging Resource Types; (3) Revising RTO/ISO Market Models, Optimization, and Other Software Elements to Address Operational Flexibility Needs; and (4) Out-of-Market Operator Actions Used to Manage Net Load Variability and Uncertainty.

White Paper. On September 7, 2021, FERC staff issued a White Paper entitled "Energy and Ancillary Services Market Reforms to Address Changing System Needs". The White Paper summarizes recent energy and ancillary services markets reforms as well as reforms currently under consideration and was prepared in an effort to frame discussions at the two technical conferences.

- **Office of Public Participation (AD21-9)**

On June 24, 2021, the FERC issued a report in which it detailed the forthcoming creation of the Office of Public Participation ("OPP"), which it intends to grow over the course of a four-year period before OPP reaches its full operating status by the close of Fiscal Year ("FY") 2024. By the end of FY2021, the FERC plans to hire the OPP Director, as well as the Deputy Director and an administrative staff member. The FERC plans to assess OPP's workload and reevaluate needed resources for additional growth into and beyond FY2024 to ensure meaningful and consistent compliance with FPA section 319. A report, prepared by M.J. Bradley & Associates for NRDC's Sustainable FERC Project, summarizing stakeholder feedback provided to the FERC through listening sessions and written comments, was posted to the FERC's eLibrary on August 3, 2021.

On August 23, 2021, the FERC issued a notice of a virtual workshop to be held on September 16, 2021, from 1:00 p.m. to 4:30 p.m., to discuss technical assistance in electric proceedings, solicit public input on their technical assistance needs, and explore ways OPP could work with external entities to facilitate technical assistance to interested parties. Further details on the agenda, including registration information, can be found on the U.S. Department of Energy's ("DOE") Pacific Northwest National Laboratory ("PNNL") website. Information on this technical workshop will also be posted on the Calendar of Events on the FERC's website, www.ferc.gov, prior to the workshop. Since the last Report, M.J. Bradley & Associates submitted a summary of stakeholder feedback provided through listening sessions and written comments and the FERC issued a supplemental notice of the workshop that indicated that the workshop would be held October 7, 2021, rather than on September 16 as previously noticed.

- **ISO/RTO Credit Principles and Practices (AD21-6)**

On February 25-26, 2021, the FERC held a technical conference to discuss principles and best practices for credit risk management in ISO/RTOs. Panel topics included: Credit Principles and Practices in ISOI/RTO Markets; RTO/ISO Comparison of Risk Management Structure, Credit Enhancements and Lessons Learned; Internal Resources and Expertise within RTOs/ISOs; Impact of Market Design on Credit Risk; Addressing Counterparty Risk: Minimum Participation Requirements and Know Your Customer Protocols; and Collateral, Initial and Variation

Margining for FTR and non-FTR positions. Speaker materials and a transcript of the technical conference are posted in the FERC's eLibrary.

On April 21, 2021, the FERC issued a notice inviting post-technical conference comments on the issues raised during the technical conference, including the questions listed in the February 24, 2021 supplemental notice of the technical conference and in the attachment to the April 21 notice. Post-technical conference comments were due on or before June 7, 2021 and were filed by ISO-NE, Appian Way, Committee of Chief Risk Officers, CPV, DC Energy, Energy Trading Institute, EPSA, Financial Marketers Coalition, ISO/RTO Council, MISO, NYISO, PJM, SPP, and Vitol. On July 6, NEPOOL filed comments in response to the IRC comments that, to the extent Tariff changes are to be proposed, the Tariff changes be vetted first pursuant to the Participant Processes set forth in the Participants Agreement. This matter is pending before the FERC.

- **Offshore Wind Integration in RTOs/ISOs Tech Conf (Oct 27, 2020) (AD20-18)**

On October 27, 2020, the FERC convened a staff-led technical conference to consider whether and how existing RTO and ISO interconnection, merchant transmission and transmission planning frameworks can accommodate anticipated growth in offshore wind generation in an efficient or cost-effective manner that safeguards open access transmission principles. The conference also provided an opportunity for participants to discuss possible changes or improvements to the current regulatory frameworks that may accommodate such growth. Speaker materials and a transcript of the technical conference are posted in eLibrary. Since the last Report, Advanced Power Alliance filed comments requesting that the FERC issue a notice providing an opportunity for interested persons to submit post-conference comments and to thereafter "take action to facilitate transmission planning and interconnection policies that will enable construction of the cost-effective, efficient, resilient and environmentally-sound transmission infrastructure needed to connect new offshore wind generation to the onshore grid."

On March 11, 2021, the FERC issued a notice inviting interested persons to file, on or before May 10, 2021, post-technical conference comments on the questions listed in the attachment to its Notice or to the questions outlined in the October 22, 2020 supplemental notice of technical conference. Post-technical conference comments were filed by over 30 parties, including: ISO-NE, NESCOE, Anbaric, ConEd, Eversource, National Grid, NRDC et al., Orsted, Shell, CT DEEP, EEI, MA DOER, RENEW et al., and RWE Renewables Americas. This matter is pending before the FERC.

- **Hybrid Resources (AD20-9)**

As previously reported, the FERC convened a July 23, 2020 technical conference to discuss technical and market issues prompted by growing interest in projects that are comprised of more than one resource type at the same plant location ("hybrid resources"). The focus was on generation resources and electric storage resources paired together as hybrid resources. Speaker materials and a transcript of the technical conference have been posted to the FERC's eLibrary. Post-technical conference comments were filed by ISO-NE, CAISO, MISO, NYISO, PJM, Enel, American Council on Renewable Energy, AWEA, EEI, EPRI, R Street Institute, Savion, and SEIA.

On January 19, 2021, the FERC issued an order directing each ISO/RTO to submit, within 6 months (or before July 19, 2021), a report that provides: (a) a description of its current practices related to each of the following four hybrid resource issues: (1) terminology; (2) interconnection; (3) market participation; and (4) capacity valuation (collectively, the "Issues"); (b) an update on the status of any ongoing efforts to develop reforms related to each of the Issues; and (c) responses to the specific requests for information contained in the order. The ISO/RTO Reports, including ISO-NE's, were filed on July 19, 2021. Public comments in response to the ISO/RTO reports are now due September 20, 2021.[114]

Hybrid Resources White Paper. On May 26, 2021, the FERC issued a white paper that discusses the hybrid resources technical conference, as well as information learned in post-technical conference comments. Interested persons were invited to submit comments on the white paper and encouraged to jointly respond to both the white paper and RTO/ISO informational reports where applicable to avoid duplicate comments. Comments on the white paper will also be due on September 20, 2021.

Comments. Comments on the RTO filing and on the FERC's Hybrid Resources White Paper were submitted by the American Council on Renewable Energy ("ACRE"), Clean Grid Alliance, EEI, the City of New York, Hybrid Resource Coalition, NRECA, Pine Gate Renewables, PJM IMM, and UCS. These matters are now pending before the FERC.

- **ANOPR: Transmission Planning and Allocation and Generator Interconnection (RM21-17)**

On July 15, 2021, the FERC issued an advanced notice of proposed rulemaking ("ANOPR")[115] to consider whether there should be changes in the regional transmission planning and cost allocation and generator interconnection processes and, if so, which changes are necessary to ensure that transmission rates remain just and reasonable and not unduly discriminatory or preferential and that reliability is maintained. Specifically, the ANOPR discusses proposals or concepts for changes to existing processes in several broad categories: regional transmission planning, regional cost allocation, generator interconnection funding, generator interconnection queueing processes and consumer protection, and in several instances the ANOPR also offers a potential rationale or argument for potential proposals. The FERC seeks comments from the public on these proposals and welcomes commenters to offer additional or alternative proposals for consideration.

Comment Deadline: October 12, 2021. On September 3, 2021, the FERC issued a notice ***denying*** the requests for an extension of time to submit comments filed by the ISO/RTO Council ("IRC"), Organization of MISO States ("OMS"), and Organization of PJM States ("OPSI"). Comments on the *Transmission Planning & Allocation/Generation Interconnection ANOPR* are still due October 12, 2021. The deadline for reply comments was extended in that September 3 notice from November 9, 2021 to November 30, 2021.

November 15, 2021 Tech Conf. On September 16, 2021, the FERC announced that it will convene remotely a staff-led technical conference regarding regional transmission planning on Monday, November 15, 2021. The technical conference will seek to examine in detail issues and potential reforms related to regional transmission planning as described in the July 15, 2021 ANOPR. Specifically, the technical conference will examine issues related to incorporating sufficiently long-term and comprehensive forecasts of future transmission needs during regional transmission planning processes, including considering the needs of anticipated future generation in identifying needed transmission facilities. This may include: approaches to planning regional transmission facilities that identify transmission needs for anticipated future generation, e.g., use in regional transmission planning of future scenarios or geographic zones where future generation is anticipated to locate; factors shaping future transmission needs that are appropriate to consider as inputs into transmission planning studies; and evaluation criteria used by the transmission planning regions to identify and select the more efficient or cost-effective regional transmission facilities.

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[114] Public comments were initially due August 18, 2021. However, in response to a request by the Energy Storage Association ("ESA"), the American Clean Power Association ("ACP"), and Solar Energy Industry Association ("SEIA"), the FERC granted a 30-day extension of time, to September 20, 2021, to file comments in response to the ISO/RTO reports.

[115] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 176 FERC ¶ 61,024 (July 15, 2021) ("*Transmission Planning & Allocation/Generation Interconnection ANOPR*").

- **NOI: Removing the DR Opt-Out in ISO/RTO Markets (RM21-14)**

On March 18, 2021, the FERC issued a NOI[116] seeking comments on whether to revise its Demand Response ("DR") Opt-Out regulations established in *Orders 719 and 719-A.* Those regulations require an ISO/RTO not to accept bids from an aggregator of retail customers ("ARC") that aggregates DR of the customers of utilities that distributed more than 4 million MWh in the previous fiscal year, where the relevant electric retail regulatory authority prohibits such customers' DR to be bid into ISO/RTO markets by an ARC. The FERC now seek information to help it examine the potential costs/burdens and benefits, both quantitative and qualitative, of removing the DR Opt-Out, as well as other changes relating to DR since the FERC issued *Orders 719 and 719-A*. The FERC is not seeking comment on the Small Utility Opt-In. Comments on the NOI, following an extension, were due on or before July 23, 2021 and were filed by nearly 30 parties, including by AEE, Voltus, AEMA, APPA/NRECA, EEI, and NARUC. Reply comments were due on or before August 23, 2021, and were filed by AEP, Armada Power, Entergy, Southern Pioneer Electric, Voltus, State Commissions from LA/MS, MI, MO, NC, APPA/NRECA, Assoc. of Bus. Advocating Tariff Equity ("ABATE"), and PIOs.

- **NOPR: Cybersecurity Incentives (RM21-3)**

On December 17, 2020, the FERC issued a NOPR[117] proposing to establish rules for incentive-based rate treatment for voluntary cybersecurity investments by a public utility for or in connection with the transmission or sale of electric energy subject to FERC jurisdiction, and rates or practices affecting or pertaining to such rates for the purpose of ensuring the reliability of the BPS.

Comments on the *Cyber security Incentives NOPR* were due on or before April 6, 2021. Comments were filed by: NECPUC, APPA, EEI, EPSA, LPPC, NERC, NRECA, TAPS, Accenture, aDolus Inc. et al.,[118] Alliant, Anterix, Bureau of Reclamation, CA Dept of Water Resources State Water Project/CPUC, George Cotter, FRS, Hitachi ABB Power Grids, IECA, ITC, Joint Consumer Advocates, MI PUC, Org of MISO States, MISO TOs, PJM TOs, and Public Citizen. Reply comments were due May 6, 2021[119] and were filed by APPA/TAPS, EEI, SEIA, California Public Utilities Commission and California Department of Water Resources ("CA PUC/DWR"), and the Office of the Ohio Federal Energy Advocate ("Ohio FEA"). This matter remains pending before the FERC.

- **NOPR: Managing Transmission Line Ratings (RM20-16)**

On November 19, 2020, the FERC issued a NOPR[120] proposing to reform both the *pro forma* OATT and its regulations to improve the accuracy and transparency of transmission line ratings. Specifically, the NOPR proposes to require: transmission providers to implement ambient-adjusted ratings on the transmission lines over which they provide transmission service; ISO/RTOSs to establish and implement the systems and procedures necessary to allow transmission owners to electronically update transmission line ratings at least hourly; and transmission owners to share transmission line ratings and transmission line rating methodologies with their respective transmission provider(s) and, in ISO/RTOs, with their respective market monitor(s). Comments on the *Managing Transmission Line Ratings NOPR* were due on or before March 22, 2021.[121] Comments were submitted by over 50 parties, including by ISO-NE, DC Energy, Dominion, EDF, ENEL/EnerNOC, Eversource, Exelon, NRDC,

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[116] *Participation of Aggregators of Retail Demand Response Customers in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 174 FERC ¶ 61,198 (March 18, 2021) ("*DR Aggregator NOI*").

[117] *Cybersecurity Incentives*, 173 FERC ¶ 61,240 (Dec. 17, 2020) ("*Cybersecurity Incentives NOPR*").

[118] These joint comments were filed by aDolus Inc., Fortress Information Security, GMO GlobalSign Inc., Ion Channel, ReFirm Labs and Reliable Energy Analytics LLC.

[119] The *Cybersecurity Incentives NOPR* was published in the *Fed. Reg.* on Feb. 5, 2021 (Vol. 86, No. 23) pp. 8,309-8,325.

[120] *Managing Transmission Line Ratings*, 173 FERC ¶ 61,165 (Nov. 19, 2020) ("*Managing Transmission Line Ratings NOPR*").

[121] The *Managing Transmission Line Ratings NOPR* was published in the *Fed. Reg.* on Jan. 21, 2021 (Vol. 86, No. 12) pp. 6,420-6,444.

Vistra, EEI, EPRI, EPSA, New England State Agencies,[122] NRECA/LPPC, and Potomac Economics. Reply comments were submitted by the Enel Companies, EPSA, PJM, OMS, Potomac Economics, NRECA/LPCC, and ITC Holdings Corp and the Utah Division of Public Utilities. This matter is pending before the FERC.

- **NOPR: Electric Transmission Incentives Policy (RM20-10)**

Supplemental NOPR. In light of comments already received in this proceeding,[123] the FERC issued on April 15, 2021 a *Supplemental NOPR*[124] to propose and seek comment on a revised incentive for transmitting and electric utilities that join Transmission Organizations ("Transmission Organization Incentive"). The Incentive would be reduced from 100 to 50 basis points and would be available only for three years. The FERC seeks comment on whether voluntary participation should be a requirement, and if so, how "voluntary" should be determined. In addition, the FERC now proposes to require each utility that has received a Transmission Organization Incentive for three or more years to submit a compliance filing revising its tariff to remove the incentive from its transmission tariff. The *Supplemental NOPR* did not address the other proposals contained in the *March NOPR*.[125] A more detailed summary of the NOPR was distributed to the Transmission Committee and discussed at the TC's March 25, 2020 meeting.

Comments on the *Supplemental NOPR* were due on or before June 25, 2021. Over 60 sets of comments were filed, including by the New England TOs, MMWEC/NHEC/CMMEC, NECOS, NESCOE, Potomac Economics, and CT PURA. Reply comments were due on or before July 26, 2021, with 28 sets of comments received, including by the New England TOs, NECOS, NESCOE, CT PURA/CT DEEP/MA AG, CT AG, and Public Interest Groups.[126] Since the

[122] "New England State Agencies" are for purposes of this proceeding: CT Att'y Gen. William Tong, MA AG Maura Healey, the CT Dept. of Energy and Environ. Protection, the CT OCC, MOPA, NH OCA, Peter F. Neronha, RI AG, and Thomas J. Donovan, Jr., VT AG. The Feb 1 comments by the New England State Agencies broadly supported the FERC's proposals.

[123] Over 80 sets of comments on the *March NOPR* were filed on or before the July 1, 2020 comment date, including comments by: Avangrid, EDF Renewables, EMCOS, Eversource, Exelon, LS Power, MMWEC/NHEC/CMEEC, National Grid, NESOCE, NextEra, UCS, CT PURA, and Potomac Economics. Reply comments were filed by AEP, ITC Holding, the N. California Transmission Agency, and WIRES.

[124] *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*, 175 FERC ¶ 61,035 (Apr. 15, 2021) ("*Supplemental NOPR*").

[125] As previously reported, the *March NOPR* proposed revisions to the FERCs existing transmission incentives policy and corresponding regulations, including the following:

- A shift from risks and challenges to a ***consumers'' benefits test*** that focuses on ensuring reliability and reducing the cost of delivered power by reducing transmission congestion.
- ***ROEs incentive for Economic Benefits***. A 50-basis-point adder for transmission projects that meet an economic benefit-to-cost ratio in the top 75th percentile of transmission projects examined over a sample period <u>and</u> an additional 50-basis-point adder for transmission projects that demonstrate *ex post* cost savings that fall in the 90th percentile of transmission projects studied over the same sample period, as measured at the end of construction.
- ***ROE for Reliability Benefits***. A 50-basis-point adder for transmission projects that can demonstrate potential reliability benefits by providing quantitative analysis, where possible, as well as qualitative analysis.
- ***Abandoned Plant Incentive***. 100 percent of prudently incurred costs of transmission facilities selected in a regional transmission planning process that are cancelled or abandoned due to factors that are beyond the control of the applicant. Recovery from the date that the project is selected in the regional transmission planning process.
- ***Eliminate Transco Incentives***.
- ***Transmission Organization Incentive*.** A *50-basis-point increase* for transmitting utilities that turn over their wholesale facilities to a Transmission Organization and *only for the first three years after transferring operational control of its facilities.* The FERC *s*eeks comment as to whether participation must be voluntary to receive the incentive, and if so, how the CFERC should determine whether the decision to join is voluntary.
- ***Transmission Technologies Incentives***. Eligible for both a stand-alone, 100-basis-point ROE incentive on the costs of the specified transmission technology project and specialized regulatory asset treatment. Pilot programs presumptively eligible (though rebuttable).
- ***250-Basis-Point Cap***. Total ROE incentives capped at 250 basis points in place of current "zone of reasonableness" limit.
- ***Updated Date Reporting Processes***. Information to be obtained on a project-by-project basis, information collection expanded, updated reporting process.

[126] "Public Interest Groups" are NRDC, Sierra Club, Sustainable FERC Project, and Western Grid Group.

last Report, reply comments were posted from New England State Parties,[127] Alliant/Consumers/DTE, AEP, Pacific Gas & Electric, Joint Consumer Advocates, and the American Clean Power Association.

September 10, 2021 Workshop. The FERC convened a workshop on September 10, 2021[128] to discuss certain performance-based ratemaking approaches, particularly shared savings, that may foster deployment of transmission technologies. The notice states that the workshop will explore: the maturity of the modeling approaches for various transmission technologies; the data needed to study the benefits/costs of such technologies; issues pertaining to access to or confidentiality of this data; the time horizons that should be considered for such studies; and other issues related to verifying forecasted benefits. The workshop also discussed whether and how to account for circumstances in which benefits do not materialize as anticipated and may explore other performance-based ratemaking approaches for transmission technologies seeking incentives under FPA section 219, particularly market-based incentives. The FERC issued an agenda for the workshop, which included the final workshop program and expected speakers, on August 23, 2021. The FERC supplemented that notice on September 9, 2021.

If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Order 2222/2222-A/2222-B*: DER Participation in RTO/ISO Markets (RM18-9)**

Order 2222. On September 17, 2020, the FERC issued a final rule ("*Order 2222*")[129] adopting reforms to remove what it found were barriers to the participation of distributed energy resource ("DER")[130] aggregations in the RTO/ISO markets. *Order 2222* requires each RTO/ISO to revise its tariff to ensure that its market rules facilitate the participation of DER aggregations. Specifically, the tariff provisions addressing DER aggregations must:

(1) allow DER aggregations to participate directly in RTO/ISO markets and establish DER aggregators as a type of market participant;

(2) allow DER aggregators to register DER aggregations under one or more participation models that accommodate the physical and operational characteristics of the DER aggregations;

(3) establish a minimum size requirement for DER aggregations that does not exceed 100 kW;

(4) address locational requirements for DER aggregations;

(5) address distribution factors and bidding parameters for DER aggregations;

(6) address information and data requirements for DER aggregations;

(7) address metering and telemetry requirements for DER aggregations;

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[127] "New England State Parties" are CT PURA, CT DEEP and the MA AG.

[128] Notice of Workshop, *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*, Docket Nos. RM20-10 and AD19-19 (Apr. 15, 2021).

[129] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 2222, 172 FERC ¶ 61,247 (Sep. 17, 2020) ("*Order 2222*").

[130] The FERC defined a DER as "any resource located on the distribution system, any subsystem thereof or behind a customer meter. These resources may include, but are not limited to, electric storage resources, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment."

(8) address coordination between the RTO/ISO, the DER aggregator, the distribution utility, and the relevant electric retail regulatory authorities;

(9) address modifications to the list of resources in a DER aggregation;

(10) address market participation agreements for DER aggregators; and

(11) Accept bids from a DER aggregator if its aggregation includes DERs that are customers of utilities that distributed more than 4 million MWh in the previous fiscal year. An RTO/ISO must not accept bids from a DER aggregator if its aggregation includes DERs that are customers of utilities that distributed 4 million MWhs or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers to be bid into RTO/ISO markets by a DER aggregator.

ISO-NE Compliance. On May 24, 2021, the FERC approved the extension of time requested by ISO-NE, to February 2, 2022 (2/2/222), to comply with *Order 2222*.[131] In granting the extension of time, as it did for MISO, SPP and PJM, the FERC directed ISO-NE to submit an informational filing indicating any changes to the stakeholder process schedule provided in its extension request on or before June 23, 2021 and to submit status reports every 90 days thereafter until the date that ISO-NE submits its compliance filing.[132] ISO-NE submitted its second report on September 21, 2021. Materials associated with ISO-NE's *Order 2222* compliance process can be viewed on the ISO-NE website's Order 2222 Key Project page.

Order 2222-A. On March 18, 2021, the FERC issued *Order 2222-A*,[133] which addressed arguments on rehearing and set aside and clarified *Order 2222* in part. Specifically, as is its right under *Allegheny*, the FERC modified the discussion in *Order 2222* and set aside *Order 2222*, in part, by finding that the participation of demand response in DER aggregations is subject to the opt-out and opt-in requirements of *Orders 719* and *719-A,* providing further clarification on the FERC's interconnection policies pertaining to Qualifying Facilities ("QFs"), and modifying § 35.28(g)(12)(i) to make a non-substantive ministerial correction. Requests for rehearing and/or clarification of *Order 2222-A* were due on or before April 19, 2021 and were filed by: AEE/AEMA (Advanced Energy Management Alliance), EEI, National Association of Regulatory Utility Commissioners ("NARUC"), Louisiana Public Service Commission ("LPSC") and the Mississippi Public Service Commission ("MPSC"), North Carolina Utilities Commission, the MISO Transmission Owners ("MISO TOs"), and Voltus. On April 30, MISO filed comments supporting the rehearing requests filed by NARUC, LPSC/MPSC and the MISO TOs. On May 4, ISO-NE answered the AEE/AEMA request for clarification and/or rehearing of *Order 2222*. On May 14, AEE/AEMA answered ISO-NE's May 4 answer.

On May 20, 2021, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration". The Notice confirmed that the 60-day period during which a petition for review of *Order 2222-A* can be filed with an appropriate federal court was triggered when the FERC did not act on the requests for rehearing of *Order 2222-A*.[134] The Notice also indicated that the FERC would address, as is its right, the rehearing requests in a future order, and may modify or set aside its orders, in whole or in part, "in such manner as it shall deem proper."[135]

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131 *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Indep. Sys. Operators*, 175 FERC ¶ 61,156 (May 24, 2021) ("*ISO-NE Order 2222 Compliance Extension*").

132 *Id.* at P 5.

133 *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Indep. Sys. Operators*, Order No. 2222-A, 174 FERC ¶ 61,197 (Mar. 18, 2021) ("*Order 2222-A*").

134 *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Indep. Sys. Operators*, 175 FERC ¶ 62,109 (May 20, 2021) ("*Notice of Denial of Rehearings By Operation of Law*").

135 *Id.*

Order 2222-B. On June 17, 2021, the FERC issued *Order 2222-B*,[136] which as permitted by FPA section 313(a), modified the discussion in *Order 2222-A* and set aside, in part, and clarified, in part, that decision. Specifically, *Order 2222-B* set aside the decision in *Order 2222-A* to decline to extend the opt-out and opt-in requirements of Order Nos. 719 and 719-A to demand response resources participating in heterogeneous distributed energy resource aggregations (finding that these issues are better addressed in Docket No. RM21-14). *Order 2222-B* also provides further clarification regarding appropriate restrictions to avoid double counting of services and the compensation of demand response resources that participate in heterogeneous distributed energy resource aggregations. *Order 2222-B* will become effective August 27, 2021.[137]

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

As previously reported, *Order 860,*[138] issued three years after the FERC's *Data Collection NOPR,*[139] (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 has posted 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. As recently extended (*see* below), *Order 860* became effective July 1, 2021, and submitters have until close of business on November 2, 2021 to make their initial baseline submissions. 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,[140] 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 denied,[141] other than TAPS' request that the FERC clarify that the public will be able to access the relational database. On that point, the FERC clarified "that we will make available services through which the public will be able to access organizational charts, asset appendices, and other reports, as well as have access to the same historical data as Sellers, including all market-based rate information submitted into the database. We also clarify that the database will retain information submitted by Sellers and that historical data can be accessed by the public."

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.

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136 *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Indep. Sys. Operators*, Order No. 2222-B, 175 FERC ¶ 61,227 (June 17, 2021) ("*Order 2222-B*").

137 *Order 2222-B* was published *Fed. Reg.* on June 28, 2021 (Vol. 86, No. 121) pp. 33,853-33,861.

138 *Data Collection for Analytics and Surveillance and Market-Based Rate Purposes*, 168 FERC ¶ 61,039 (July 18, 2019) ("*Order 860*"), *order on reh'g and clarif.*, 170 FERC ¶ 61,129 (Feb. 20, 2020).

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

140 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.

141 *Data Collection for Analytics and Surveillance and Market-Based Rate Purposes*, Order No. 860-A, 170 FERC ¶ 61,129 (Feb. 20, 2020) ("*Order 860-A*").

March 18 Notice. On March 18, 2021, the FERC issued a notice seeking comments on proposed changes to the MBR Data Dictionary to reflect the affiliations, or lack of affiliation, among Sellers for which their ultimate upstream affiliate is an institutional investor who acquired their securities pursuant to a section 203(a)(2) blanket authorization.[142] Specifically, the FERC proposes to update the MBR Data Dictionary and add the following three new attributes to the Entities table: the blanket authorization docket number, and the utility ID types and the utility IDs of the utilities whose securities were purchased under the corresponding blanket authorization docket number. Appropriate Sellers would be required to submit the docket number of the proceeding in which the FERC granted the section 203(a)(2) blanket authorization and the upstream affiliate whose securities were acquired pursuant to the section 203(a)(2) blanket authorization. Comments on the Notice were due on or before June 7, 2021,[143] and were filed by EEI, the Global LEI Foundation, TAPS, and XBRL US. In light of the proposed changes, the FERC deferred by three months the effective date of *Order 860* and its associated deadlines.

Effective Date: July 1, 2021; Baseline Submissions November 2, 2021; First change in Status Filings, November 30, 2021. On March 18, 2021, the FERC issued a notice extending the effective and associated implementation dates of *Order 860* by an additional *three* months. The new *Order 860* effective date was July 1, 2021, and the deadline for baseline submissions will be to and including November 2, 2021. First change in status filings under these new timelines will be due November 30, 2021.

Order Adopting Changes to MBR Database. On August 19, 2021, the FERC issued an order revising the MBR Data Dictionary as proposed in the March 18 Notice.[144] Specifically, Sellers whose ultimate upstream affiliate(s) own their voting securities pursuant to a section 203(a)(2) blanket authorization must provide, in the MBR Database, three additional data fields: (1) the docket number of the section 203(a)(2) blanket authorization, (2) the Utility_ID_Type_CD of the utility whose securities were acquired under the corresponding section 203(a)(2) blanket authorization docket number, and (3) the Utility ID of that utility.

- ***Order 676-J*: Incorporation of NAESB WEQ Standards v. 003.3 into FERC Regs (RM05-5-029, -030)**

On May 20, 2021, the FERC issued Order 676-J,[145] which revises FERC regulations to incorporate by reference the latest version (Version 003.3) of the 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"). The WEQ Version 003.3 Standards include, in their entirety, the WEQ-023 Modeling Business Practice Standards contained in the WEQ Version 003.1 Standards, which address the technical issues affecting Available Transfer Capability ("ATC") and Available Flowgate Capability ("AFC") calculation for wholesale electric transmission services, with the addition of certain revisions and corrections. The FERC also revised its regulations to provide that transmission providers must avoid unduly discriminatory and preferential treatment in the calculation of ATC. *Order 676-J* became effective August 2, 2021.[146] Public utilities must make a compliance filing to comply with the requirements of this final rule through eTariff 12 months after implementation of the WEQ Version 003.2 Standards. Compliance filings for cybersecurity and Parallel Flow Visualization standards are due March 2, 2022.

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142 *Data Collection for Analytics and Surveillance and Market-Based Rate Purposes*, 174 FERC ¶ 61,214 (Mar. 18, 2021).

143 The Notice was published *Fed. Reg.* on Apr. 6, 2021 (Vol. 86, No. 64) pp. 17,823-17,828.

144 *Data Collection for Analytics and Surveillance and Market-Based Rate Purposes*, 176 FERC ¶ 61,109 (Aug. 19, 2021).

145 *Standards for Business Practices and Communication Protocols for Public Utilities*, Order No. 676-J, 175 FERC ¶ 61,139 (May 20, 2021) ("*Order 676-J*").

146 *Order 676-J* was published *Fed. Reg.* on June 2, 2021 (Vol. 86, No. 104) pp. 29,491-29,503.

- **Waiver of Tariff Requirements (PL20-7)**

On May 21, 2020, the FERC issued a Proposed Policy Statement that would clarify its policy regarding requests for waiver of tariff provisions.[147] The *Proposed Policy Statement* sets forth the approach the FERC would take going forward to ensure compliance with the filed rate doctrine and the rule against retroactive making. The proposed policy will both clarify and modify waiver standards, and in some instances, make it harder to obtain waivers.

Specifically, the FERC proposed the following guidance on filing procedures to implement its new approach for granting waivers of tariff provisions and to no longer grant retroactive waivers except as consistent with the *Proposed Policy Statement*:

1. *Style Requests as Requests for Remedial Relief*. Filings seeking relief in connection with actions or omissions that have already occurred prior to the date relief is sought from the FERC would be characterized as a request for remedial relief (rather than as a request for a waiver). In response to such a request, the FERC will focus on what remedy, if any, is required to cure acknowledged or alleged deviations from a filed tariff. "Waiver" is to be limited to (a) requests for prospective relief when a requested future deviation from the filed tariff has not yet occurred at the time a request is filed; or (b) petitions for remedial relief when a tariff expressly authorizes regulated entities to seek a remedial waiver from the FERC for past non-compliance with the filed tariff.

2. *Form of Filing*. When the entity requesting remedial relief is the entity that acted (or believes it may have acted) in a manner inconsistent with the tariff, such requests should be filed as petitions for declaratory order under Rule 207 of the FERC's Rules of Practice and Procedure. When the filing entity alleges a different entity has acted in a manner inconsistent with the tariff, such requests should be filed as complaints under Rule 206. Given the filing fees associated with petitions for declaratory order, the industry was encouraged to directly address this aspect of the proposal.

3. *Expressly Request FERC Action pursuant to FPA section 309 or NGA section 16.4*. These provisions have been found to afford the FERC the latitude to remedy past non-compliance "provided the agency's action conforms with the purposes and policies of Congress and does not contravene any terms of the Act."

The FERC acknowledged that this Policy would represent a change from its past approach, particularly in situations where inadvertent failures to comply with ministerial tariff requirements have not been protested. The FERC suggested a few ways tariffs may be modified to avoid what may appear by comparison to be harsh outcomes, including expressly stating in the tariff that a failure to comply with a certain deadline may be waived by order of the FERC or by allowing various kinds of errors to be cured within a reasonable period of time after a default has occurred or an error has been discovered, but is difficult to imagine how feasible or how well these options might work in practice.

The FERC proposed to incorporate its current four-part analysis[148] in considering both requests for prospective waiver and petitions for remedial relief, but cautioned that it would apply that analysis only in those limited circumstances where the request for remedial relief would not violate the filed rate doctrine or

[147] *Waiver of Tariff Requirements*, 171 FERC ¶ 61,156 (May 21, 2020) ("*Proposed Policy Statement*").

[148] Under current practice, the FERC grants tariff provision waivers where: (1) the underlying error was made in good faith; (2) the waiver is of limited scope; (3) the waiver addresses a concrete problem; and (4) the waiver does not have undesirable consequences, such as harming third parties.

the rule against retroactive ratemaking due to adequate prior notice, or the requested relief is within the FERC's authority to grant under FPA section 309 or NGA section 16.

Finally, the FERC proposed requiring a stronger showing when a petitioner is seeking remedial relief for its own failure to comply with a tariff – petitions will be more compelling when the failure to comply was due to something more than inadvertent error or administrative oversight. Petitions for remedial relief will generally be denied when a protestor credibly contends, or the FERC independently determines, that the requested remedial relief will result in undesirable consequences (e.g. harm to third parties).

With respect to prospective requests to waive the 60-day prior notice requirement under FPA section 205(d) (or the 30-day prior notice requirement under NGA section 4(d)), which the FERC has discretion to waive "for good cause shown," the FERC proposes to leave in effect its policy of generally granting such waivers,[149] to the extent that entities seek an effective date no earlier than the day *after* the date a rate change is submitted to the FERC.

Comments on the Proposed Policy Statement were due on or before June 18, 2020 and were filed by the IRC, AEE, APPA, AWEA/SEIA, EEI, EPSA, Indicated Generators,[150] INGAA, Kansas Electric Power Coop. ("KEPC"), NGA, NGSA, NRECA, Public Citizen, Sunflower Electric Power, and TAPS. Reply comments were filed by APPA, Joint Trade Associations,[151] KEPC, and the Sustainable FERC Project. The proposed Policy Statement remains pending before the FERC.

- **FERC's ROE Policy for Natural Gas and Oil Pipelines (PL19-4)**

On May 21, 2020, the FERC issued a Policy Statement that applies to natural gas and oil pipelines, with certain exceptions to account for the statutory, operational, organizational and competitive differences among the electric, natural gas and oil pipeline industries, the FERC's ROE methodology adopted in *Opinion No. 569-A*.[152] Specifically, the FFERC revised its policy and will determine natural gas and oil pipeline ROEs by averaging the results of the DCF and CAPM, but will not use the risk premium model discussed in *Opinion 569/569-A* ("Risk Premium").[153] In addition, the FERC clarified its policies governing the formation of proxy groups and the treatment of outliers in proceedings addressing natural gas and oil pipeline ROEs. Finally, the FERC encouraged oil pipelines to file revised FERC Form No. 6, page 700s for 2019 reflecting the revised ROE policy. This Policy Statement became effective May 27, 2020.[154] On July 7, the FERC issued a notice that pipelines choosing to file updated FERC Form No. 6, page 700 data consistent with the ROE Policy Statement should file such data on or before July 21, 2020.

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[149] *See Cent. Hudson Gas & Elec. Corp.*, 60 FERC ¶ 61,106, *order on reh'g*, 61 FERC ¶ 61,089 (1992) ("*Central Hudson*"). Factors that will generally support a waiver of prior notice include: (1) uncontested filings that do not change rates; (2) filings that reduce rates and charges; and (3) filings that increase rates as prescribed by a previously accepted contract or settlement on file with the FERC.

[150] "Indicated Generators" are Vistra, NRG, FirstLight, Cogentrix, and LS Power.

[151] "Joint Trade Associations" are AEE, AWEA, EEI, EPSA, INGAA, NGSA, NRECA and SEIA.

[152] *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 171 FERC ¶ 61,155 (May 21, 2020) ("*Natural Gas and Oil Pipeline ROE Policy Statement*").

[153] As previously reported, the FERC issued a notice of inquiry on March 21, 2019 seeking information and views to help the FERC explore whether, and if so how, it should modify its policies concerning the determination of ROE to be used in designing jurisdictional rates charged by public utilities.[153] The FERC also sought comment on whether any changes to its policies concerning public utility ROEs should be applied to interstate natural gas and oil pipelines. This NOI followed *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).

[154] The *Natural Gas and Oil Pipeline ROE Policy Statement* was published *Fed. Reg.* on May 27, 2020 (Vol. 85, No. 102) pp. 31,760-31,773.

Complainant-Aligned Parties[155] answered the New England TO's May 10 supplemental comments. On June 15, 2020, Joint Parties[156] submitted supplemental comments arguing that the FERC should use the midpoint, rather than the median, as the measure of central tendency for public utilities that file individually to establish a ROE. Joint Parties' comments were opposed by Six Cities.[157] WIRES submitted supplemental comments on June 18, 2020 requesting that the FERC take further action in this proceeding to "resolve the uncertainty surrounding its base ROE methodology and establish a policy consistent with the recommendations made in these comments" (recommending a framework that employs all four of the previously proposed ROE models, including the Expected Earnings model, along with certain modifications, to ensure that ROEs attract capital investment in needed transmission infrastructure). On June 24, EEI and WIRES requested the FERC issue a NOI regarding the FERC's policy for determining base ROE applicable to the electric industry as a whole. Six Cities answered Joint Parties on June 30. APPA answered EEI and WIRES' June 24 motion.

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

As previously reported, the FERC's February 18, 2021 notice of inquiry ("*2021 NOI*") sought new information and additional stakeholder perspectives to help the FERC explore whether it should revise its approach under the currently effective policy statement on the certification of new natural gas transportation facilities to determine whether a proposed natural gas project is or will be required by the public convenience and necessity, as that standard is established in NGA section 7.[158] The *2021 NOI* is to provide an opportunity for stakeholders to refresh the record and provide updated information and additional viewpoints to help the FERC assess its policy.[159] Comments on the *2021 NOI* were due May 26, 2021. In all, more than 130 sets of comments were filed, including a large number from concerned private citizens. This matter is pending before the FERC.

XIII. FERC Enforcement Proceedings

Electric-Related Enforcement Actions

- **PacifiCorp (IN21-6)**

On April 15, 2021, in the FERC's first-ever Show Cause Order addressing alleged violations of NERC Reliability Standards,[160] the FERC directed PacifiCorp to show cause why it should not be found to have violated FPA section 215(b)(1) and section 39.2 of the FERC's regulations by failing to comply with Reliability Standard FAC 009-1 (Establish and Communicate Facility Ratings), Requirement R1, and the successor Reliability Standard FAC-008-3 (Facility Ratings), Requirement R6 (collectively, "FAC-009-1 R1"), which requires a transmission owner to establish and have facility ratings that are consistent with its Facility Ratings Methodology ("FRM"). An Enforcement investigation found that clearance measurements on a majority of PacifiCorp's transmission lines were incorrect under the National Electric Safety Code, which were used to calculate PacifiCorp's facility ratings, thus making PacifiCorp's facility ratings inconsistent with its FRM. Enforcement alleges that PacifiCorp was aware of incorrect clearances on its system since at least 2007 when

[155] For this purpose, "Complainant-Aligned Parties" are: Connecticut Public Utilities Regulatory Authority, Connecticut Office of the Attorney General, Connecticut Department of Energy and Environmental Protection, Connecticut Office of Consumer Counsel, Massachusetts Office of the Attorney General, Massachusetts Department of Public Utilities, Massachusetts Municipal Wholesale Electric Company, and New Hampshire Electric Cooperative.

[156] "Joint Parties" are: AEP, Avista, Evergy Companies, Entergy Services, Exelon, FirstEnergy, Portland Gen. Elec., PG&E, Corporation, Puget Sound Energy, PacifiCorp, Idaho Power, PSEG, So. Cal. Edison, and San Diego Gas & Elec.

[157] "Six Cities" are the Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California.

[158] *Certification of New Interstate Natural Gas Facilities*, 174 FERC ¶ 61,125 (Feb. 18, 2021) ("2021 NOI").

[159] *Id.* at P 3.

[160] *PacifiCorp,* 175 FERC ¶ 61,039 (Apr. 15, 2021) ("*PacifiCorp Show Cause Order*").

FAC-009-1 R1 became mandatory, but failed to identify and remedy them in a timely manner, and PacifiCorp's violations began on August 31, 2009, when it implemented its FRM policy, and at least some of the violations continued until August 2017 when PacifiCorp completed remediation of all of its incorrect clearances to make them consistent with its FRM. Enforcement also pointed to the role of the violations in the Wood Hollow, Utah wildfire that lasted from June 23 to July 1, 2012. In light of these alleged violations, the FERC directed PacifiCorp to show cause why it should not be assessed civil penalties in the amount of ***$42 million***.

On July 16, 2021, PacifiCorp answered the PacifiCorp Show Cause Order, denying the alleged violations of FAC-009. Enforcement filed its reply on September 14, 2021. Should the FERC choose to pursue a civil penalty against PacifiCorp for the alleged violations, PacifiCorp has already exercised its right to adjudicate these allegations in federal district court. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **GreenHat (IN18-9)**

On May 20, 2021, the FERC directed GreenHat Energy, LLC ("GreenHat"), John Bartholomew, Kevin Ziegenhorn, and [Luan Troxel as the Executor for] the Estate of Andrew Kittell ("Kittell Estate") (collectively, "Respondents") to show cause why they should not be found to have violated FPA section 222, along with section 1c.2 of the FERC's regulations, PJM Tariff Attachment Q, Section B and section 15.1.3 of PJM's Operating Agreement, by engaging in a manipulative scheme in PJM's Financial Transmission Rights ("FTR") market which generated more than $13 million in unjust profits for Respondents and imposed approximately $179 million in losses on PJM Members.[161] The FERC directed GreenHat, Bartholomew, Ziegenhorn, and the Kittell Estate to show cause why they should not be required, jointly and severally, to disgorge unjust profits of just ***over $13 million***, plus interest, and directed GreenHat, Bartholomew, and Ziegenhorn (but not the Kittell Estate) to show cause why they should not be assessed civil penalties of ***$179 million***, ***$25 million***, and ***$25 million***, respectively.

Respondents answered the *GreenHat Show Cause Order* on July 6, 2021. On July 27, Enforcement Litigation Staff answered Respondents' July 6 answers. On August 23, 2021, the Estate of Andrew Kittell submitted a reply to Enforcement's July 27 answer. This matter is again before the FERC. As previously reported, should the FERC choose to pursue a civil penalty against Respondents for the alleged violations, Respondents have already exercised their right to adjudicate these allegations in federal district court. Since the last Report, OE issued a notice that, should the FERC decide to issue a penalty order, the date by which the FERC needs to do so to ensure that a lawsuit against the Kittell Estate will be timely is October 11, 2021. In an interesting twist, OE lawyers reported on October 1, 2021 on improper communications (forwarding some precedential decisions regarding statute of limitations) from a decisional staff member to another lawyer who is working on the GreenHat litigation. In response, the Kittell Estate requested on October 5, 2021 that the FERC drop all enforcement action against the Estate, ban OE staff Messrs. Tabackman and Olson from any future involvement, and order other offices within the FERC to investigate.

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

Natural Gas-Related Enforcement Actions

- ***Rover Pipeline, LLC and Energy Transfer Partners, L.P. (IN19-4)***

On March 18, 2021, the FERC issued a show cause order[162] in which it directed Rover Pipeline, LLC ("Rover") and Energy Transfer Partners, L.P. ("ETP" and together with Rover, "Respondents") to show cause why they should not be found to have violated Section 157.5 of the FERC's regulations by misleading the FERC in its

161 *GreenHat Energy, LLC et al.*, 175 FERC ¶ 61,138 (May 20, 2021) ("*GreenHat Show Cause Order*").

162 *Rover Pipeline, LLC, and Energy Transfer Partners, L.P.*, 174 FERC ¶ 61,208 (Mar. 18, 2021) ("*Rover/ETP Show Cause Order*").

Application for Certificate of Public Convenience and Necessity under NGA section 7(c).[163] The FERC directed Respondents to show cause why they should not be assessed civil penalties in the amount of ***$20.16 million***. On April 5, 2021, the FERC extended by 60 days, to June 18, 2021, the deadline for Respondents' answer. On June 18, 2021, Rover and ETP answered the *Rover/ETP Show Cause Order*, asserting that the FERC should dismiss this matter and decline to initiate an enforcement action. On July 21, 2021, Enforcement Staff answered Rover/ETP's answer, stating the evidence supports a finding that Rover violated the FERC's Regulations and should be assessed the civil penalty identified in the *Rover/ETP Show Cause Order*. Rover answered the July 21 answer on September 15. This matter is pending before the FERC.

- ***BP (IN13-15)***

On December 17, 2020, the FERC issued *Opinion 549-A*,[164] a 159-page decision addressing arguments raised on rehearing requested of *Opinion 549.*[165] *Opinion 549-A* modifies the discussion in *Opinion 549*, but reaches the same the result (ultimately requiring BP to pay a ***$20.16 million civil penalty (roughly $24.4 million with accrued interest) and disgorge $207,169***). Of note, *Opinion 549-A* denied BP's motion to dismiss this enforcement action as time barred (by the five-year statute of limitations set forth in 28 U.S.C. § 2462), finding BP waived any statute of limitations defense by failing to raise it earlier in this proceeding.[166] Opinion 549-A revised Ordering Paragraph (C) to direct the disgorged profits to non-profits that disburse the Low Income Home Energy Assistance Program of Texas funds, rather than to the Texas Department of Housing.[167]

On December 29, 2020, BP filed a notice that it intends to appeal *Opinion 549-A* to the Fifth Circuit Court of Appeals and paid the civil penalty amount on December 28, 2020, under protest and with full reservation of rights pending the outcome of judicial review of that Opinion. On January 19, BP filed a notice that it disgorged $250,295 ($207,169 principal plus interest), divided equally ($83,431.67) among the following 3 entities identified in the "2016 Comprehensive Energy Assistance Program Subrecipient List": Dallas County Dept. of Health and Human Services (serving Dallas); El Paso Community Action, Project Bravo (Serving El Paso); and Panhandle Community Services (serving Armstrong and numerous other counties), again under protest and with full reservation of rights pending the outcome of judicial review of *Opinion 549/549-A*.

- ***Total Gas & Power North America, Inc. et al. (IN12-17)***

On April 28, 2016, the FERC issued a show cause order[168] 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

[163] Specifically, Rover stated that it was "committed to a solution that results in no adverse effects" to the Stoneman House, an 1843 farmstead located near Rover's largest proposed compressor station. In truth, the OE Staff Report alleges, Rover was simultaneously planning to purchase the house with the intent to demolish it, if necessary, to complete its pipeline. The OE Staff Report alleges that Rover purchased the house in May 2015 and demolished the house in May 2016. The OE Staff Report further finds that despite taking these actions during the year and a half that Rover's application was pending before the FERC, Rover did not notify the FERC that it purchased the Stoneman House, intended to destroy the Stoneman House, and did destroy the Stoneman House. The OE Staff Report therefore concludes that Rover violated section 157.5's requirement for full, complete and forthright applications, through its misrepresentations and omissions, when it decided not to tell FERC that it had purchased the house and was considering demolishing it, and when Rover demolished it in May 2016 without notifying FERC.

[164] *BP America Inc. et al.,* Opinion No. 549-A, 173 FERC ¶ 61,239 (Dec. 17, 2020) ("*BP Penalties Allegheny Order*")

[165] *BP America Inc.*, Opinion No. 549, 156 FERC ¶ 61,031 (July 11, 2016) ("*BP Penalties Order*") (affirming Judge Cintron's Aug. 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 FERC's regulations ("Anti-Manipulation Rule") and NGA Section 4A (*BP America Inc.et al,* 152 FERC ¶ 63,016 (Aug. 13, 2015) ("*BP Initial Decision*")).

[166] *BP Penalties Allegheny Order* at P 1.

[167] *Id*. at P 319.

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

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.[169]

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.

On July 15, 2021, the FERC issued and order establishing hearing procedures to determine whether Respondents violated the FERC's Anti-Manipulation Rule, and to ascertain certain facts relevant for any application of the FERC's Penalty Guidelines.[170] On July 27, Chief Judge Cintron designated Judge Suzanne Krolikowski as the Presiding ALJ and established an extended Track III Schedule[171] for the proceeding. Judge Krolikowski scheduled and convened on August 26, 2021 a prehearing conference in this proceeding.

Since the last Report, Judge Krolikowski issued an order confirming her rulings from the August 26 prehearing conference and establishing a procedural schedule that calls for, among other dates, pre-hearing briefs by July 25, 2022, hearings (estimated to take 2-3 weeks) to begin on August 15, 2022, and an initial decision on January 9, 2023. However, on September 21, Chief Judge Cintron concurrently designated Judge Joel deJesus as Settlement Judge to convene a settlement conference, explore the possibility of settlement, discuss the differences between the parties, and generally conduct settlement negotiations in this matter, directing Judge deJesus to issue status reports to her every 60 days. In light of that development, Respondents and OE Staff moved to temporarily suspend the procedural schedule for about six weeks to "allow the Participants to direct all of their resources towards fully participating in settlement discussions." Chief Judge Cintron granted the motion, extending the hearing commencement and initial decision deadlines to September 26, 2022, and February 20, 2023, respectively. Settlement judge procedures are underway, with a first settlement conference scheduled for October 15, 2021.

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[169] 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 NGA section 4A 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.

[170] *Total Gas & Power North America, Inc. et al.,* 176 FERC ¶ 61,026 (July 15, 2021).

[171] The hearing in this proceeding will be convened within 55 weeks (Aug. 15, 2022) and the initial decision issued within 76 weeks (January 9, 2023) of the issuance of the Chief Judge's order.

XIV. Natural Gas Proceedings

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

New England Pipeline Proceedings
The following New England pipeline projects are currently under construction or before the FERC:

- ***Iroquois ExC Project (CP20-48)***
  - 125,000 Dth/d of incremental firm transportation service to ConEd and KeySpan by building and operating new natural gas compression and cooling facilities at the sites of four existing Iroquois compressor stations in Connecticut (Brookfield and Milford) and New York (Athens and Dover).
  - Three-year construction project; service request by November 1, 2023.
  - February 2, 2020 application for a certificate of public convenience and necessity pending; Iroquois requests on January 26, 2021 that the FERC act promptly and issue the certificate; National Grid and ConEd submit comments supporting Iroquois' application and request for action.
  - On May 27, 2021, FERC staff issued a notice that it will prepare an environmental impact statement ("EIS") for this Project, which will respond to comments filed on the Environmental Assessment, and plans to release that EIS on September 3, 3021.
  - On June 11, 2021, FERC staff issued a notice that it has prepared a draft EIS for this Project, which responds to comments on the September 30, 2020 Environmental Assessment, and with the exception of greenhouse gas ("GHG") emissions, concludes that approval of the proposed Project, with the mitigation measures recommended in the EIS, would not result in significant environmental impacts. FERC staff did not come to a determination of significance with regards to GHG emissions. Comments on the draft EIS were due on or before August 9, 2021. Since the last Report, 93 sets of individual comments were filed, bring to nearly 300 the number of individual comments have been filed. Algonquin responded to those comments on August 24, 2021.
  - On September 2, 2021, FERC staff modified the issuance date of its final EIS for the Project, due to the "complexity of comments received on the draft EIS". Issuance of a final EIS is now expected on November 12, 2021; the 90-day Federal Authorization Decision Deadline, February 9, 2022.
  - On September 3, 2021, FERC staff issued environmental information request #4, to which Iroquois responded on September 13, 2021.

- ***Atlantic Bridge Project (CP16-9)***
  - On February 24, 2020, the FERC authorized Algonquin Gas Transmission, LLC ("Algonquin") and Maritimes & Northeast Pipeline, LLC ("Maritimes") to place facilities associated with the Atlantic Bridge Project into service.[172] Rehearing of the *Authorization Order* was timely requested, but denied by operation of law.
  - *Briefing Order*. In a fairly unprecedented order issued February 18, 2021,[173] the FERC, expressing concerns regarding operation of the project, established briefing on the following matters:
    - In light of the concerns expressed regarding public safety, is it consistent with the FERC's responsibilities under the NGA to allow the Weymouth Compressor Station to enter and remain in service?
    - Should the Commission reconsider the current operation of the Weymouth Compressor Station in light of any changed circumstances since the project was authorized? For example,

[172] *Algonquin Gas Transmission, LLC*, Docket No. CP16-9 at 1 (Sep. 24, 2020) (delegated order) ("*Authorization Order*").

[173] *Algonquin Gas Transmission, LLC and Maritimes & Northeast Pipeline, LLC*, 174 FERC ¶ 61,126 (Feb. 18, 2021) ("*Briefing Order*").

are there changes in the Weymouth Compressor Station's projected air emissions impacts or public safety impacts the Commission should consider? We encourage parties to address how any such changes affect the surrounding communities, including environmental justice communities.

- Are there any additional mitigation measures the Commission should impose in response to air emissions or public safety concerns?
- What would the consequences be if the Commission were to stay or reverse the *Authorization Order*?

- Requests for rehearing of the *Briefing Order* were filed by Algonquin, NGSA and Center for Liquefied Natural Gas, and by America and Energy Infrastructure Council. Cheniere Energy submitted comments in support of the requests for rehearing. On April 19, 2021, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[174] The Notice confirmed that the 60-day period during which a petition for review of its *Briefing Order* can be filed with an appropriate federal court was triggered when the FERC did not act on the requests for rehearing of the *Briefing Order*. The Notice also indicated that the FERC would address, as is its right, the rehearing requests in a future order, and may modify or set aside its orders, in whole or in part, "in such manner as it shall deem proper." On May 19, the FERC issued that order,[175] dismissing the requests for rehearing of the *Briefing Order*, noting, over the objection of Commissioner Danly, that the *Briefing Order* was an exercise of the FERC's continuing oversight of the Project (meaning the claimed harms would be speculative and premature) and Algonquin and Trade Associations will have an opportunity to submit, if they choose, in requests for rehearing of any final decision by the Commission in this proceeding. Algonquin petitioned the DC Circuit for review of the *Briefing Order* and the notice of denial by operation of law on May 3, 2021 (*see* Section XVI below).
- Requests for rehearing of the *May 19 Order* were filed by Algonquin and INGAA. On July 16, 2021, the FERC issued a Notice of Denial of Rehearings by Operation of Law of the requests for rehearing of the *May 19 Order*.
- Algonquin also petitioned the DC Circuit for review of the *Briefing Order*, *April 19 Notice of Denial of Rehearings by Operation of Law*, and the *May 19 Order*.[176]
- This matter is before the DC Circuit (*see* Section XVI below).

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.[177] Those orders have been challenged on appeal to the US Court of Appeals for the Second Circuit (19-1610).

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[174] *Algonquin Gas Transmission, LLC and Maritimes & Northeast Pipeline, LLC*, 175 FERC ¶ 62,022 (Apr. 19, 2021) ("*April 19 Notice of Denial of Rehearings by Operation of Law*").

[175] *Algonquin Gas Transmission, LLC and Maritimes & Northeast Pipeline, LLC*, 175 FERC ¶ 61,150 (May 19, 2021) ("*May 19 Order*").

[176] *Algonquin Gas Transmission, LLC and Maritimes & Northeast Pipeline, LLC*, 176 FERC ¶ 62,029 (July 16, 2021) ("*July 16 Notice of Denial of Rehearings by Operation of Law*").

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

- 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*.[178] 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,[179] 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.[180] The Allegheny Defense Project and Sierra Club (collectively, "Allegheny") requested rehearing of the *Northern Access Certificate Order*.
- Despite the FERC's *Northern Access Certificate Order*, the project remained halted pending the outcome of National Fuel's fight with the NY DEC's April denial of a Clean Water Act permit. NY DEC found National Fuel's application for a water quality certification under Section 401 of the Clean Water Act, as well as for stream and wetlands disturbance permits, failed to comply with water regulations aimed at protecting wetlands and wildlife and that the pipeline failed to explore construction alternatives. National Fuel appealed the NY DEC's decision to the 2nd Circuit on the grounds that the denial was improper.[181] 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,[182] provided a "more clearly articulate[d] basis for denial."
- On August 27, 2019, 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.[183]

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[178] *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).

[179] 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).

[180] *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*").

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

[182] 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).

[183] *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).

- On October 16, 2020, Applicants requested, due to ongoing legal and regulatory delays, an additional 2-year extension of time, until December 1, 2024, to complete construction of the Project and enter service. More than 50 sets of comments on the requested extension were filed and on December1, 2020, the FERC dismissed, without prejudice, Applicants' request for an extension of time, [184] finding the request premature. The FERC reiterated its encouragement that pipeline applicants requesting extensions "file their requests no more than 120 days before the deadline to complete construction", so that the FERC has the relevant information available to determine whether good cause exists to grant an extension of time and whether the FERC's prior findings remain valid.[185]

XV. State Proceedings & Federal Legislative Proceedings

- **New England States' Vision Statement**

In October 2020, the six New England states released their "Vision Statement", outlining their vision for "a clean, affordable, and reliable 21st century regional electric grid" and committing to engage in a collaborative and open process, supported by NESCOE, intended to advance the principles discussed in the Vision Statement. As part of that effort, the following series of online technical forums to discuss the issues presented in the Vision Statement were held:

Jan 13, 2021	Wholesale Market Reform
Jan 25, 2021	Wholesale Market Reform
Feb 2, 2021	Transmission Planning
Feb 25, 2021	Governance Reform
Mar 18, 2021	Equity and Environmental Justice

Written comments on the topics and discussions addressed in the on the equity and environmental justice topics and discussions were, following an extension, due by May 13, 2021. Comments submitted are posted on **NewEnglandEnergyVision.com**. Recordings of the technical forums, as well as draft notices, agendas, and additional information on these sessions, are also available on the New England States' Vision Statement website (https://newenglandenergyvision.com/).

Report to the Governors. On June 29, 2021, the NESCOE Managers published their Progress Report to the New England Governors Regarding "Advancing the New England Energy Vision". The Report was further discussed at the August 5, 2021 Participants Committee meeting. View Report here.

ISO-NE Board Response. On September 23, 2021, the ISO-NE Board responded to the New England States' Vision Statement and Advancing the Vision Report. A copy of that response was included with the materials for the October 7 Participants Committee meeting and is posted on the ISO-NE website here.

XVI. 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 ("DC 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

[184] *National Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 173 FERC ¶ 61,197 (Dec. 1, 2020).

[185] *Id.* at P 10.

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).

- **ISO-NE Implementation of Order 1000 Exemptions for Immediate Need Reliability Projects (20-1422)**
  Underlying FERC Proceeding: EL19-90[186]
  Petitioner: LS Power
  Status: Briefing Complete; Pending Court Action

On October 16, 2020, LSP Transmission Holdings II, LLC ("LS Power") petitioned the DC Circuit Court of Appeals for review of the FERC's orders addressing ISO-NE's implementation of the Order 1000 exemptions for immediate need reliability projects. Since the last Report, MMWEC filed on July 8 a notice that it would not submit a Reply Brief. On July 9, 2021, LSP Transmission filed Petitioner's Reply Brief. LSP Transmission filed a Joint Appendix on July 16. On July 28, 2021, MMWEC filed an Intervenor for Petitioner Final Brief. Final Briefs were filed on July 30, 2021. Briefing is now complete and this matter is pending before the Court.

- **CIP IROL Cost Recovery Rules (20-1389)**
  Underlying FERC Proceeding: ER20-739[187]
  Petitioner: Cogentrix, Vistra
  Status: Briefing Complete; Oral Argument Scheduled for Nov 12

On September 25, 2020, Cogentrix and Vistra petitioned the DC Circuit Court of Appeals for review of the FERC's orders allowing for recovery of expenditures to comply with the IROL-CIP requirements, but only those costs incurred on or after the effective date of the relevant individual FPA section 205 filing, including undepreciated costs of any such past capital expenditures to comply with the IROL-CIP requirements. Cogentrix and Vistra filed a Deferred Appendix (July 16, 2021) and Final Briefs (from Petitioners and the FERC) were submitted on July 26, 2021. Briefing is now complete. On September 22, 2021, the Court scheduled oral argument for Friday, November 12, 2021. The composition of the argument panel will be revealed on or about October 12, 2021 on the Court's web site at www.cadc.uscourts.gov.

- **Mystic 8/9 Cost of Service Agreement (20-1343; 20-1361, 20-1362; 20-1365, 20-1368; 21-1067; 21-1070)(consolidated)**
  Underlying FERC Proceeding: EL18-1639[188]
  Petitioners: Mystic (20-1343), NESCOE (20-1361, 21-1067), MA AG (20-1362), CT Parties (20-1365, 20-1368, 21-1070)
  Status: Briefing Underway

Mystic, NESCOE, MA AG, and CT Parties have separately petitioned the DC Circuit Court of Appeals for review of the FERC's orders addressing the COS Agreement among Mystic, ExGen and ISO-NE.[189] The cases have been consolidated into Case No. 20-1343. On February 17 and 24, 2021, the Court consolidated with 20-1343 the most recent appeals in cases 21-1067 (NESCOE) and 21-1070 (CT Parties), respectively. On March 25, 2021, the Court issued an order returning this case to its active docket. On March 26, the Court granted the interventions by

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[186] *ISO New England Inc., 171 FERC ¶ 61,211 (June 18, 2020) ("Order Terminating Proceeding")* (finding (i) "insufficient evidence in the record to find under FPA section 206 that [ISO-NE's] implementation of the exemption for immediate need reliability projects is unjust, unreasonable, or unduly discriminatory or preferential; (ii) "insufficient evidence in the record to find that ISO-NE implemented the immediate need reliability project exemption in a manner that is inconsistent with or more expansive than [the FERC] directed"; and (iii) that ISO-NE complies with the five criteria established for the immediate need reliability project exemption); and *ISO New England Inc.,* 172 FERC ¶ 61,293 (Sep. 29, 2020) *("Order 1000 Exemptions Allegheny Order")* (addressing arguments raised by request for rehearing denied by operation of law, modifying discussion in *Order Terminating Proceeding,* but reaching same result).

[187] *ISO New England Inc.*, 171 FERC ¶ 61,160 (May 26, 2020) ("*CIP IROL Cost Recovery Order*") and *ISO New England Inc.*, 172 FERC ¶ 61,251 (Sep. 17, 2020) ("*CIP IROL Allegheny Order*", and together with the CIP IROL Cost Recover Order, the "*CIP IROL Orders*").

[188] *July 2018 Order*; *July 2018 Rehearing Order*; *Dec 2018 Order*; *Dec 2018 Rehearing Order; Jul 17 Compliance Order*.

[189] The COS Agreement is to provide compensation for the continued operation of the Mystic 8 & 9 units from June 1, 2022 through May 31, 2024.

MMWEC/NHEC, NESCOE, and ENECOS. On April 16, 2021, the Court ordered the parties to file, and the parties did file, by May 17, 2021, proposed formats for the briefing of these cases.

On June 23, 2021, the Court established a briefing schedule. Thus far, FERC filed a Certified Index to the Record (on July 12, 2021); Mystic and State Petitioners filed Opening Briefs (September 7, 2021); and Intervenor for State Petitioners filed their Brief (September 21, 2021). Next up are Respondent's (FERC's) Brief (December 6, 2021); Intervenors for Respondents' Briefs (December 20, 2021); Reply Briefs (February 3, 2022); Joint Appendix (February 17, 2022); and Final Briefs (February 24, 2022). The date for oral argument and the composition of the merits panel will be identified at a later time.

- ***CASPR* (20-1333, 20-1331) (consolidated)****
  Underlying FERC Proceeding: ER18-619[190]
  Petitioners: Sierra Club, NRDC, RENEW Northeast, and CLF
  Status: Being Held in Abeyance

On August 31, 2020, the Sierra Club, NRDC, RENEW Northeast, and CLF petitioned the DC Circuit Court of Appeals for review of the FERC's order accepting ISO-NE's CASPR revisions (which, under *Allegheny*, is ripe for review). On October 2, 2020, appearances, docketing statements, a statement of issues to be raised, and a statement of intent to utilize deferred joint appendix were filed. On October 19, 2020, the FERC moved to dismiss the case for a lack of jurisdiction (arguing that Petitioners missed their opportunity to timely file their Petition for review in 2018, and filing within 60 days of *Allegheny* did not make their Petition timely). Alternatively, the FERC asked that the case be held in abeyance for 60 days pending issuance of a further FERC order on this matter. On October 29, Petitioners opposed the FERC's motion. On November 5, 2020, the FERC filed a reply, indicated that an order on rehearing would be issued imminently and suggested that, if the Court declines to dismiss the petition, it should be held in abeyance until the Commission issues an order on rehearing. As noted above, the FERC issued the *CASPR Allegheny Order* on November 19, modifying the discussion in the *CASPR Order*, but reaching the same the result. The Sierra Club, NRDC and CLF also requested rehearing of the November 19 order.

On January 12, 2021, the Court dismissed as moot the FERC's October 19 motion to hold this proceeding in abeyance and ordered that the motion to dismiss be referred to the merits panel (Judges Pillard, Katsas and Walker) and addressed by the parties in their briefs. On January 25 and 26, CT Parties and MMWEC and NHEC filed statements of issues and notices that they intend to participate in support of Petitioners. On January 27, the Court ordered the parties to submit by February 26, 2021, proposed formats for the briefing of these cases. On March 24, 2021, the Court granted NEPOOL's intervention and established a briefing schedule that, as explained just below, has since been superseded.

On April 7, 2021, the Court granted Petitioners' motion to hold this matter in abeyance, pending further order of the Court. The parties were directed to file motions to govern future proceedings in these cases on or before October 22, 2021.

- ***Opinion 531-A* Compliance Filing Undo (20-1329)**
  Underlying FERC Proceeding: ER15-414[191]
  Petitioners: TOs' (CMP et al.)
  Status: Being Held in Abeyance

On August 28, 2020, the TOs[192] petitioned the DC Circuit Court of Appeals for review of the FERC's October 6, 2017 order rejecting the TOs' filing that sought to reinstate their transmission rates to those in place prior to the

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

[191] *ISO New England Inc.*, 161 FERC ¶ 61,031 (Oct. 6, 2017) ("*Order Rejecting Filing*").

[192] The "TOs" are CMP; Eversource Energy Service Co., on behalf of its affiliates CL&P, NSTAR and PSNH; National Grid; New Hampshire Transmission; UI; Unitil and Fitchburg; VTransco; and Versant Power.

FERC's orders later vacated by the DC Circuit's *Emera Maine*[193] decision. On September 22, 2020, the FERC submitted an unopposed motion to hold this proceeding in abeyance for four months to allow for the Commission to "a future order on petitioners' request for rehearing of the order challenged in this appeal, and the rate proceeding in which the challenged order was issued remains ongoing before the Commission." On October 2, 2020, the Court granted the FERC's motion, and directed the parties to file motions to govern future proceedings in this case by February 2, 2021. On January 25, 2021, the FERC requested that the Court continue to hold this petition for review in abeyance for an additional three months, with parties to file motions to govern future proceedings at the end of that period. The FERC requested continued abeyance because of its intention to issue a future order on petitioners' request for rehearing of the order challenged in this appeal, and the rate proceeding in which the challenged order was issued remains ongoing before the FERC. Petitioners consented to the requested abeyance. On February 11, 2021, the Court issued an order that that this case remain in abeyance pending further order of the court. On April 21, 2021, the FERC filed an unopposed motion for continued abeyance of this case *because* the Commission intends to issue a future order on Petitioners' request for rehearing of the challenged Order Rejecting Compliance Filing, and because the remand proceeding in which the challenged order was issued remains ongoing.

On May 4, *2021*, the Court ordered that this case remain in abeyance pending further order of the court, directing the FERC to file a status report by September 1, 2021 and at 120-day intervals thereafter. The parties were directed to file motions to govern future proceedings in this case within 30 days of the completion of agency proceedings. On August 24, the FERC submitted a status report indicating that the proceedings before the Commission remain ongoing and that this appeal should continue to remain in abeyance.

- **2013/14 Winter Reliability Program Order on Compliance and Remand (20-1289, 20-1366) (consol.)**
  Underlying FERC Proceeding: ER13-2266[194]
  Petitioner: TransCanada
  Status: Briefing Complete; Oral Argument Scheduled for Oct 15

On July 30, 2020, TransCanada Power Marketing ("Petitioner" or "TransCanada") again petitioned the DC Circuit Court of Appeals for review of the FERC's action on the 2013/2014 Winter Reliability Program, this time in the FERC's April 1, 2020 *2013/14 Winter Reliability Program Order on Compliance and Remand*.[195] NEPGA intervened on October 15, 2020 (and its intervention granted on October 28). On October 16, TransCanada filed a docketing statement and statement of issues. On October 29, the FERC filed a certified index to the record and an unopposed motion for a 60-day briefing period. On December 2, 2020, the Court granted the FERC's October 29 motion. On January 11, 2021, TransCanada submitted its initial brief. On March 12, FERC filed its Respondent Brief. Since the last Report, TransCanada filed Petitioner's Reply Brief on April 9, 2021 and the Deferred Appendix on April 16. TransCanada filed its Final Brief on April 30, 2021. Briefing is now complete. On August 6, the Court scheduled oral argument for Friday, October 15, 2021. Petitioner and Respondents were each allotted 10 minutes. The argument panel will be comprised of Judges Srinivasan, Henderson and Edwards.

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

[194] 171 FERC ¶ 61,003 (Apr. 1, 2020) ("*2013/14 Winter Reliability Program Order on Compliance and Remand*") (accepting ISO-NE's January 23, 2017 compliance filing, finding that the bid results from the 2013/14 Winter Reliability Program were just and reasonable, and providing for this finding the further reasoning requested by the DC Circuit in *TransCanada Power Mktg. Ltd. v. FERC*, 811 F.3d 1 (DC Cir. 2015) ("*TransCanada*").)

[195] In TransCanada, the DC Circuit granted TransCanada's prior petition in part, and directed the FERC to either better justify its determination or revise its disposition to ensure that the rates under the Program are just and reasonable. *TransCanada* at 1.

- **ISO-NE's Inventoried Energy Program (Chapter 2B) Proposal (19-1224***; 19-1247; 19-1252; 19-1253)(consolidated); Underlying FERC Proceeding: ER19-1428**[196]
  Petitioners: ENECOS (Belmont et al.) (19-1224); MA AG (19-1247); NH PUC/NH OCA (19-1252); Sierra Club/UCS (19-1253)
  Status: Briefing Complete; Oral Argument Scheduled for Oct 21

As previously reported, at the unopposed request of the FERC, the Court issued an order suspending the previous briefing schedule and remanding the record back to the FERC. Subsequently, the FERC issued its *IEP Remand Order* (June 18, 2020) and its Notice of Denial by Operation of Law of the requests for rehearing of its *IEP Remand Order* (August 20, 2020). As previously reported, each of the Petitioners filed amended petitions for review in the consolidated proceeding in order to bring the FERC's *IEP Remand Order* and the post-remand FERC record before the DC Circuit. On November 10, 2020, the Court ordered that the cases be removed from abeyance. Opening Briefs from Petitioners were filed on December 11, 2020. The FERC filed its Respondent Brief on February 9. Intervenor for Respondent Briefs were filed on February 16 by ISO-NE and NEPGA. On February 24, the FERC filed an amended certified index to the record. Petitioners' Reply Brief was filed on March 30, 2021. The Deferred Appendix was filed on April 20, 2021. Final Briefs were filed on May 4, 2021. Briefing is now complete. The argument panel for the October 21 oral argument will be comprised of Judges Wilkins, Katsas and Jackson.

Other Federal Court Activity of Interest

- ***Order 872* (20-72788,* 21-70113; 20-73375, 21-70113) (consol.) (9th Cir.)**
  Underlying FERC Proceeding: RM19-15[197]
  Petitioners: SEIA et al.
  Status: Briefing Again Underway

On September 17, 2020, SEIA petitioned the 9th Circuit Court of Appeals for review of *Order 872*.[198] On October 9, the FERC filed an unopposed motion for the Court to hold this appeal in abeyance, suspend filing of the certified index to the record, and issue a new briefing schedule after January 4, 2021. The abeyance was to permit the FERC to address the pending rehearing requests in a future order. On October 26, 2020, the Court granted the FERC's motion. On January 29, 2021, SEIA requested that this case be consolidated with the others, and that the abeyance period be extended to give the parties additional time to coordinate and develop a unified, efficient briefing schedule.

On March 25, 2021, the Court granted SEIA's unopposed March 5, 2021 motion to lift the stay in this proceeding. Briefing has resumed. On May 27, 2021, Petitioners' briefs were filed by SEIA and Other Petitioners.[199] On June 28, 2021, petitioner-intervenors filed their joint brief and (June 28, 2021); motions and associated briefs by amici curiae in support of petitioners were also filed on June 28, 2021. NewSun Energy filed an Intervenor Brief on July 28. Since the last Report, Respondent's brief was filed on September 27. Next up will be: joint brief of respondent-intervenors (October 27, 2021); motions and associated briefs by amici curiae in support of respondent (October 27, 2021); and any optional reply briefs (December 13, 2021).

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[196] 162 FERC ¶ 61,127 (Feb. 15, 2018) ("*Order 841*"); 167 FERC ¶ 61,154 (May 16, 2019) ("*Order 841-A*").

[197] *Transcontinental Gas Pipe Line Co., LLC*, 159 FERC ¶ 62,181 (Feb. 3, 2017); *Transcontinental Gas Pipe Line Co., LLC*, 161 FERC ¶ 61,250 (Dec. 6, 2017).

[198] *Order 872* approved pricing and eligibility revisions to the FERC's long-standing regulations implementing sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA"), including: state flexibility in setting QF rates; a decrease (to 5 MW) to the threshold for a rebuttable presumption of access to nondiscriminatory, competitive markets; updates to the "One-Mile Rule"; clarifications to when a QF establishes its entitlement to a purchase obligation; and provision for certification challenges.

[199] "Other Petitioners" are Montana Environmental Information Center, Sierra Club, Center for Biological Diversity, Vote Solar, Appalachian Voices, Energy Alabama, Georgia Interfaith Power & Light, North Carolina Sustainable Energy Association, Upstate Forever, and Community Renewable Energy Association.

- **PennEast Project (18-1128)**
  Underlying FERC Proceeding: CP15-558[200]
  Petitioners: NJ DEP, DE and Raritan Canal Commission, NJ Div. of Rate Counsel
  Status: Briefing Again Underway

The Supreme Court proceedings up on which abeyance in this proceeding had been based ended on August 2, 2021. The parties filed a motion to govern future proceedings on September 1, 2021, suggesting that supplemental briefing was in order. On September 13, 2021, the Court ordered that Petitioners and Respondents file supplemental briefs on November 12, 2021.

- **Opinion 569/569-A: FERC's Base ROE Methodology (16-1325, 20-1182, 20-1240, 20-1241, 20-1248, 20-1251, 20-1267, 20-1513) (consol.)**
  Underlying FERC Proceeding: EL14-12; EL15-45[201]
  Petitioners: MISO TOs, Transource Energy, Dec 23 Petitioners et al.
  Status: Briefing Complete; Oral Argument Scheduled for Nov 18

The MISO Transmission Owners (TOs), Transource and "Dec 23 Petitioners",[202] among others, have appealed *Opinion 569/569-A*. The MISO TOs' case has been consolidated with previous appeals that had been held in abeyance, with the lead case number assigned as 16-1325. The FERC filed a certified Index to the Record on December 3, 2020, the Parties filed a joint unopposed briefing schedule on December 23, 2020. Statements of issues were filed on February 8, 2021. Petitioners' Briefs were filed on March 10. On March 17, 2021, a motion to participate as amicus curiae was jointly filed by NEP, CPM, Eversource, Fitchburg and Unitil, NHT, VTransco, Versant Power, and UI ("New England Parties") (that motion was granted on April 30, 2021). On March 18, New England Parties submitted an amicus brief in support of Transmission Owning Petitioners. On March 24, 2021, Intervenors in Support of Petitioners[203] filed their Brief. FERC filed its Respondent brief on June 8 and Intervenors in Support of FERC their Joint Brief on June 22, 2021. Petitioners' and Joint Petitioners' Reply Briefs were filed on July 8, 2021; Intervenors in Support of Petitioners Reply Briefs, July 22, 2021. The Joint Deferred Appendix was filed on August 5, 2021; Final Briefs on August 19, 2021. Briefing is now complete. On September 22, 2021, the Court scheduled oral argument for November 18, 2021. The composition of the argument panel will be revealed on or about October 18, 2021 on the Court's web site at www.cadc.uscourts.gov.

- **Algonquin Atlantic Bridge Project Briefing Order (21-1115*, 21-1138, 21-1153, 21-1155) (consol.);**
  Underlying FERC Proceeding: CP16-9-012[204]
  Petitioners: LS Power, Algonquin, INGA
  Status: Case Being Held in Abeyance

On May 3, 2021, Algonquin petitioned the DC Circuit Court of Appeals for review of the *Briefing Order* and the *April 19 Notice of Denial of Rehearings by Operation of Law*. Appearances, docketing statements and a statement of issues were due and filed June 4, 2021. Also on June 4, 2021, the FERC filed an unopposed motion to hold this proceeding in temporary abeyance, until August 2, 2021, including the fling of the certified index to the record, because "the May 3 petition for review no longer reflects the [FERC]'s latest determination in this matter."

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

[201] *Transcontinental Gas Pipe Line Co., LLC*, 159 FERC ¶ 62,181 (Feb. 3, 2017); *Transcontinental Gas Pipe Line Co., LLC*, 161 FERC ¶ 61,250 (Dec. 6, 2017).

[202] "Dec 23 Petitioners" are: Assoc. of Bus. Advocating Tariff Equity; Coalition of MISO Transmission Customers: IL Industrial Energy Consumers; IN Industrial Energy Consumers, Inc.; MN Large Industrial Group; WI Industrial Energy Group; AMP; Cooperative Energy; Hoosier Energy Rural Elec. Coop.; MS Public Service Comm.; MO Public Service Comm.; MO Joint Municipal Electric Utility Comm.; Organization of MISO States, Inc.; Southwestern Elec. Coop., Inc.; and Wabash Valley Power Assoc.

[203] The Intervenors for Petitioners Brief was filed by Citizens Utility Board of Wisconsin, Illinois Citizens Utility Board, Indiana Office of Utility Consumer Counselor, Iowa Office of Consumer Advocate, Louisiana Public Service Commission, Michigan Citizens Against Rate Excess, Minnesota Department of Commerce, and Missouri Office of Public Council.

[204] *Briefing Order*; *April 19 Notice of Denial of Rehearings by Operation of Law*

The Court granted the first abeyance motion. On August 27, 2021, the Court granted a second abeyance motion by the FERC, directing the parties to file motions to govern future proceedings by October 29, 2021.

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II. Rate, ICR, FCA, Cost Recovery Filings

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

IV. OATT Amendments/Coordination Agreements

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Updates

VII. NEPOOL Agreement/Participants Agreement Amendments

VIII. Regional Reports

IX. Membership Filings

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

XI. Misc. Regional Interest

XII. Misc: Administrative & Rulemaking Proceedings

XIII. FERC Enforcement Proceedings

XIV. Natural Gas Proceedings

XV. State Proceedings & Federal Legislative Proceedings

XVI. Federal Courts