NEPOOL
NEW ENGLAND POWER POOL

**David T. Doot**
Secretary

November 23, 2021

**VIA ELECTRONIC MAIL**

**TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES**

**RE:** Supplemental Notice of the December 2, 2021 NEPOOL Participants Committee Annual Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that the December meeting of the Participants Committee, the annual meeting for the Committee, will be held **in person on *Thursday*, December 2, 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/. **The meeting will be preceded by a Holiday Breakfast beginning at 8:30 a.m. that we hope you will attend**. We note in particular that FERC Commissioner Clements is planning to join in person, as are ISO Board Chair Cheryl LaFleur and new ISO Board member Caryn Anders. We encourage members to attend in person if they are able.

**If you plan to attend the meeting in person and have not yet informed us of your plans for attendance, please e-mail Kathryn Dube of your plans as soon as possible.** Additionally, there are a limited number of rooms available at the Colonnade Hotel for the evening before the December 2 meeting. If you wish to take advantage of the arrangements that have been made, please contact Kathryn Dube (kdube@daypitney.com) to confirm availability.

For your information, the December 2 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.

By way of reminder, the December annual meeting is the time before which any Participant that wishes to change its Sector for next year ***must provide us with written notice of that request.*** Under Section 6.3 of the NEPOOL Agreement, any Participant request to change the Sector in which it votes becomes effective *at the first annual meeting following that request*.

We will hold a New Member Orientation following the meeting for anyone wishing to learn more about or dive deeper into the aspects of the NEPOOL stakeholder process. There are 36 entities that have become NEPOOL members in 2021. Representatives of these new members and anyone else wanting to learn more about the NEPOOL stakeholder process are welcome and encouraged to attend. Please let Pat Gerity (pmgerity@daypitney.com) know if you plan to attend the New Member Orientation so we can ensure sufficient space and copies of materials.

We have included with this notice the safety protocols that will be in effect for in-person attendance at the December 2 Participants Committee Annual 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 during an indoor meeting except when actively eating or drinking. Additional safety measures are outlined in the protocols. As with any in-person meeting, there will be COVID-related risks associated with in-person attendance at the December 2 Participants Committee Annual 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 December 2 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**.

Looking ahead to the new year, the January 6, 2022 Participants Committee meeting will be held at the Seaport Boston Hotel, 1 Seaport Lane, Boston, MA. There will be a block of rooms available at the Seaport for the evening before that meeting. Rate and reservation deadline information will follow. Please contact Kathryn Dube (kdube@daypitney.com) with any questions regarding or to take advantage of those arrangements.

Finally, may you all enjoy your time spent with loved ones and friends over this Thanksgiving holiday.

Respectfully yours,

/s/
David T. Doot, Secretary

# FINAL AGENDA

1. To approve the draft minutes of the November 3, 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 Reliability Committee set forth on the Consent Agenda included with this supplemental notice and posted with the meeting materials.

3. To receive comments from the Honorable Allison Clements, Commissioner of the Federal Energy Regulatory Commission.

4. To receive an ISO Chief Executive Officer report. The December CEO report is included with this supplemental notice and posted with the meeting materials

5. To receive a report from the ISO Chief Operating Officer. The December COO report will be circulated and posted in advance of the meeting.

6. To receive the 2021 NEPOOL Annual Report, which will be distributed at the Participants Committee meeting and posted with the meeting materials.

6A. To consider and take action, as appropriate, on revisions to Sections I and II of the ISO-NE Tariff to add a process for the conduct of Longer-Term Transmission Studies. Background materials and a draft resolution are included with this supplemental notice and posted with the meeting materials.

7. To elect NEPOOL Participants Committee Officers for 2022. A draft resolution reflecting the outcome of the balloting for Participants Committee Chair and candidates for Secretary and Assistant Secretary is included and posted with the supplemental notice**.**

8. To adopt a NEPOOL Budget for 2022. Background materials and a draft resolution are included with this supplemental notice and posted with the meeting materials.

9. 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.

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

11. Administrative matters.

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

**eff. September 22, 2021**

**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.

[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 $^0$F (38.0 $^0$C) 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.

## PRELIMINARY

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held beginning at 2:00 p.m. on Wednesday, November 3, 2021, following meetings between each of the Sectors and ISO Board members. 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 meeting, either in person or by phone.

Mr. David Cavanaugh, Chair, presided, and Mr. David Doot, Secretary, recorded.

## APPROVAL OF OCTOBER 7, 2021 MEETING MINUTES

Mr. Cavanaugh referred the Committee to the preliminary minutes of the October 7, 2021 meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of that meeting were unanimously approved as circulated.

## 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 approved as circulated, with oppositions noted by Calpine, ~~Cross Sound~~Cross-Sound Cable (CSC) and LIPA, and abstentions noted by FirstLight, Great River Hydro, Nautilus, and Wheelabrator. The representatives for CSC and LIPA noted that their opposition related to Consent Agenda Items 1 and 2 (HQICC Values and Installed Capacity Requirement (ICR) and Related Values for the 2022-23 3rd Annual Reconfiguration Auction (ARA), 2023-24 2nd ARA, and 2024-2 1st ARA) (together the ARA Values) because of their previously conveyed positions that those values do not properly account for the reliability benefits and capacity import capability of the Cross-Sound Cable. The representative for Great River Hydro, Nautilus and Wheelabrator, as well as the FirstLight representative, explained that those Participants abstained because the ARA Values included tie benefits in the calculation of capacity requirements recommended by the Reliability Committee. Echoing those same concerns, the Calpine representative explained that Calpine's opposition was related to the use of tie benefits (or any non-firm, non-committed external capacity) in the determination of ICR values.

## ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), shared with the Committee the recent announcement of the vaccination requirement for all ISO employees by December 31, 2021 and a January 4, 2022 date for a return to the office in a hybrid fashion.

## ISO COO REPORT

### *Operations Highlights*

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), began by referring the Committee to his November report, which had been circulated and posted in advance of the meeting. Dr. Chadalavada noted that the data in the report was through October 26, 2021, unless otherwise noted. The report highlighted: (i) Energy Market value for October 2021 was $469 million, down $42 million from the updated September 2021 value of $511 million and up $231 million from October 2020; (ii) October 2021 average natural gas prices were 5.5% higher than September average prices; (iii) average Real-Time Hub Locational Marginal Prices (LMPs) for October ($55.08/MWh) were 18% higher than September averages; (iv) average October 2021 natural gas prices and Real-Time Hub LMPs over the period were up 139% and 105%, respectively, from October 2020 average prices; (v) average Day-Ahead cleared physical energy during peak hours as percent of forecasted load was 99.9% during September (up from the 99.8% reported for September), with the minimum value for the month of 95.9% on October 26; and (vi) Daily Net Commitment Period Compensation (NCPC) payments for October totaled $3.1 million, which was up $1.7 million from September 2021 and up $0.3 million from October 2020. October NCPC payments, which were 0.7% of total Energy Market value, were comprised of $2.4 million in first contingency payments (up $1 million from September 2021) and $0.7 million in second contingency payments, with no voltage or distribution payments for the month.

Dr. Chadalavada noted that transmission outages for the replacement of structures would occur on line 312/393 from Northfield to Alps from November 14 to 24 and again from November 29 to December 18, 2021. Those outages would reduce imports to and exports from New York by 700 MW. Additionally, transmission line 365, from Auburn to North Cambridge, Massachusetts, would be out from November 7 to December 18. He then reported on an October 26-27 Nor'easter that resulted in 12 transmission line trips, which were restored within 24 to 48 hours, and affected approximately 600,000 customers. In response to questions, he reported that no emergency procedures or out-of-market actions were required in response to the storm. Master/Local Control Center Procedure No. 2 was declared on October 26 at 1:00 p.m. and cancelled on October 28 at approximately 4:00 p.m. Generation resources were minimally impacted and actual loads were below peak load projections.

***New England Winter Outlook 2021/2022***

Turning to the New England winter outlook, Dr. Chadalavada noted that, based on data available at that point, ~~with a~~including an expected "La Niña" effect~~ expected, December~~

~~through February had~~, there was a 40-50% probability ~~of~~that temperatures would be above normal ~~temperatures~~during December through February for all of New England. While there was an equal chance for above or below average precipitation, he reminded the Committee that above average precipitation would likely result in short term reductions in solar photovoltaic (~~pv~~PV) output of approximately 30% before snow could be cleared from the panels and ~~pv~~PV installations restored to their full output.

In response to a question about the load forecast comparison from last winter to the upcoming winter, Dr. Chadalavada noted that, based on experiences during the pandemic in which demand was 2-3% higher than historic levels during times of extreme heat or cold, the ISO would be prepared for a similarly higher (2-3%) energy demand if temperatures were lower and more extreme than expected. Discussing oil inventories for the winter, he explained that oil could be delivered into New England in three ways: via barge, pipeline and truck. Delivery by pipeline would provide more reliable supply during the winter compared to delivery by barge or truck. The ISO was in constant communication with those asset owners relying on oil inventories to ensure uninterrupted service. He reported further that New England had 73 generating stations, with approximately 12,800 MW of combined capability, that ~~utilize~~use oil as a primary or alternate fuel. He noted that 70% of those MW use distillate fuel (or light oil), but account for only 31% of the tankage. Two-thirds of the region's tankage was associated with the smaller percentage using heavy oil, spread over a few sites that have a large amount of storage.

Dr. Chadalavada then discussed the high level ~~winter assessment included in the~~ winter assessment report which predicted how the system might perform (1) if winter 2021/22 were similar to the mild 2020/21 winter, (2) if winter 2021/22 were similar to winter 2017/18 when, despite milder than normal temperatures overall, there was a stretch of cold weather with two weeks' of temperatures well (10 degrees) below normal, with significant disruptions in natural gas availability, high oil usage and several units postured to maintain reserves, and (3) if winter 20221/22 were similar to winter 2013/14, when there was an extended and extreme cold snap in New England, highlighted by a polar vortex event. He noted that the region could experience periodic rolling blackouts during extreme weather should there not be LNG deliveries that could be counted on; however, with adequate fuel replenishment, the system could be operated reliably without the need for emergency procedures. He assured members that the ISO was reaching out to resource owners to more completely understand the supply situation. He further confirmed in response to a question that the ISO assumed in its predictive modeling that it continued successfully to implement OP-21 to optimize the fuel situation in the region.

***Operational Impact of Extreme Weather Events***

Dr. Chadalavada then discussed the extreme weather assessment project, which would be worked on with the Electric Power Research Institute (EPRI), as a result of the extreme events in Texas and California, and would leverage the ongoing "Resource Adequacy for a Decarbonized Future." He indicated that this project was expected to take 15-18 months and would continue through the end of 2022~~/~~ and into early 2023. The results, which would allow the ISO to prepare appropriately for extreme weather events, was expected to show the risks associated with such conditions.

## PARTICIPANT-SPONSORED PROPOSAL TO REVISE SCHEDULE 11 OF SECTION II OF THE ISO TARIFF

Ms. Emily Laine, Reliability Committee Chair, referred the Committee to the materials circulated and posted in advance of the meeting related to the proposal from NextEra on behalf of RENEW Northeast to revise Schedule 11 of Section II of the ISO's Transmission, Markets and Services Tariff. The proposal would revise Schedule 11 so that annual costs associated with Distribution Upgrades, Stand Alone Network Upgrades and Network Upgrades would no longer be allocated to Interconnection Customers, but instead would be recovered from Transmission Customers. She reported that the Transmission Committee had considered a motion to recommend Participants Committee approval and that motion had failed.

At the request of the Chair, NEPOOL counsel explained that, under these circumstances, proponents of the proposal were not required to seek Participants Committee action in order to confirm that the Participants Committee did not support the proposal. However, the proponent, or any other interested member, could seek a Participants Committee vote if desired. The NextEra representative indicated NextEra did not see the need for a Participants Committee vote under the circumstances and the Chair confirmed that no other member sought a vote.

**LITIGATION REPORT**

Mr. Doot referred the Committee to the November 2 Litigation Report that had been circulated and posted the morning of the meeting. He highlighted the following:

(i) The ISO and NESCOE budgets were submitted to FERC in mid-October. Comments on those filing were due the following day and orders on those filings were expected before the end of the year;

(ii) Many comments had been filed recently in response to the FERC's Advanced Notice of Proposed Rulemaking (ANOPR) on transmission planning and allocation and generator interconnection issues. Reply comments were due November 30. The FERC planned to hold a technical conference on this issue on November 15;

(iii) The FERC investigation into Section I.3.10 and Schedule 25 to the Tariff had upcoming deadlines to note: the ISO filing required by the FERC's order was due the following Monday, November 8, and, based on the expected ISO filing, comments in response would be due within 60 days of that submission;

(iv) Oral arguments were held October 21 before the U.S. Court of Appeals for the D.C. Circuit (DC Circuit) on the appeal of the FERC's order approving the ISO's Inventoried Energy Program (IEP) filing. A decision of the Court would follow in due course; and

(v) The candidacy of DC Public Service Commissioner Willie Phillips to fill the fifth and still empty seat on the FERC continued, with the Senate Energy and Natural Resources Committee unanimously recommending him to the full Senate for final approval.

**COMMITTEE REPORTS**

***Markets Committee (MC)***. Mr. William Fowler, the MC Vice-Chair, reported that the next MC meeting would take place on November 9-10 and was expected to take place virtually given the low number of persons that had registered to attend in person. The November 9-10 meeting would focus on the External Market Monitor's report, expected to be released shortly, on suggested changes to the Cost of New Entry in connection with removal of the Minimum Offer Price Rule.

***Reliability Committee (RC)***. Mr. Robert Stein, the RC Vice-Chair, reported that the next regularly-scheduled RC meeting, November 16, would likely be held virtually.

***Transmission Committee (TC)***. Mr. José Rotger, the TC Vice-Chair, reported that the scheduled November 19 TC meeting would take place virtually and would include a vote on the

Attachment K changes that would allow the ISO to perform ~~longer-term transmission planning analysis~~Longer-Term Transmission Studies.

***Budget & Finance Subcommittee.*** Mr. Kaslow reported that the next B&F Subcommittee meeting was scheduled for November 29, and would include a review of the 2022 NEPOOL Budget. He reminded members whose Participants had in place a letter of credit (LOC) to satisfy their additional financial assurance requirements to be sure to provide to the ISO an updated, conforming LOC on before December 31, 2021.

**ADMINISTRATIVE MATTERS**

Mr. Doot reported that the Participants Committee Annual Meeting would take place on December 2 at the Colonnade. He noted that FERC Commissioner Allison Clements had been invited and indicated she would attend. He further reminded the Committee that the election of Committee officers would take place at that meeting, as well as circulation of the 2021 annual report.

Lastly, Mr. Cavanaugh reminded Participants of the Future Grid Pathways meeting planned for December 6 at a location yet to be determined.

There being no other business, the meeting adjourned at 3:35 p.m.

Respectfully submitted,

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David Doot, Secretary

ATTACHMENT 1

## PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
## PARTICIPATING IN ~~NOV~~THE NOVEMBER 3, 2021 MEETING

| PARTICIPANT NAME | SECTOR/ GROUP | MEMBER NAME | ALTERNATE NAME | PROXY |
|---|---|---|---|---|
| Acadia Center | End User | Melissa Birchard (tel) | | |
| American Petroleum Institute | Fuels Industry Participant | Paul Powers (tel) | | |
| AR Large Renewable Generation (RG) Group Member | AR-RG | Alex Worsley | | |
| Ashburnham Municipal Light Plant | Publicly Owned Entity | | Brian Thomson | |
| Associated Industries of Massachusetts (AIM) | End User | | | Mary Smith (tel) |
| AVANGRID: CMP/UI | Transmission | Alan Trotta | Jason Rauch (tel) | |
| Bath Iron Works Corporation | End User | | | William P. Short III |
| 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; John Flumerfelt |
| Castleton Commodities Merchant Trading | Supplier | | | Bob Stein (tel) |
| Central Rivers Power | AR-RG | Kevin Telford | Dan Allegretti | |
| Chester Municipal Light Department | Publicly Owned Entity | | Dave Cavanaugh | |
| Chicopee Municipal Lighting Plant | Publicly Owned Entity | | Brian Thomson | |
| Concord Municipal Light Plant | Publicly Owned Entity | | Dave Cavanaugh | |
| Connecticut Municipal Electric Energy Coop. | Publicly Owned Entity | Brian Forshaw (tel) | | |
| Connecticut Office of Consumer Counsel (CT OCC) | End User | | Dave Thompson (tel) | |
| Conservation Law Foundation (CLF) | End User | Phelps Turner (tel) | | |
| Cross-Sound Cable Company (CSC) | Supplier | | José Rotger | |
| Danvers Electric Division | Publicly Owned Entity | | Dave Cavanaugh | |
| Dick Brooks | End User | Dick Brooks | JoAnn Brooks | |
| Dominion Energy Generation Marketing | Generation | Mike Purdie (tel) | | |
| DTE Energy Trading, Inc. | Supplier | | | José Rotger |
| Durgin and Crowell Lumber Co., Inc. | End User | | | William P. Short III |
| Dynegy Marketing and Trade, LLC | Supplier | Andy Weinstein | | Arnie Quinn; Bill Fowler |
| Elektrisola, Inc. | End User | | | William P. Short III |
| 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 (tel) | | |
| Eversource Energy | Transmission | James Daly | Dave Burnham | Vandan Divatia |
| 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 | | 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 | | Bob Stein (tel) | |
| Harvard Dedicated Energy Limited | End User | Joyceline Chow (tel) | | |
| 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 | |

**PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES**
**PARTICIPATING IN ~~NOV~~THE NOVEMBER 3, 2021 MEETING**

| PARTICIPANT NAME | SECTOR/ GROUP | MEMBER NAME | ALTERNATE NAME | PROXY |
|---|---|---|---|---|
| Ipswich Municipal Light Department | Publicly Owned Entity | | Brian Thomson | |
| Jericho Power LLC (Jericho) | AR-RG | Mark Spencer | Nancy Chafetz | Marji Philips |
| King Forest Industries, Inc. | End User | | | William P. Short III |
| Littleton (MA) Electric Light and Water Department | Publicly Owned Entity | | Dave Cavanaugh | |
| Long Island Power Authority (LIPA) | Supplier | Bill Kilgoar (tel) | | |
| Maine Power LLC | Supplier | Jeff Jones (tel) | | |
| Maine Public Advocate's Office | End User | Drew Landry (tel) | | Erin Camp (tel) |
| 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 | | |
| 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 | |
| Middleborough Gas & Electric Department | Publicly Owned Entity | | Dave Cavanaugh | |
| Middleton Municipal Electric Department | Publicly Owned Entity | | Dave Cavanaugh | |
| Moore Company | End User | | | William P. Short III |
| National Grid | Transmission | Tim Brennan (tel) | Tim Martin | |
| Natural Resources Defense Council | End User | Bruce Ho (tel) | | |
| Nautilus Power, LLC | Generation | Dan Pierpont | Bill Fowler | |
| New Hampshire Electric Cooperative | Publicly Owned Entity | Steve Kaminski | | Brian Forshaw (tel); Dave Cavanaugh; Brian Thomson |
| New Hampshire Office of Consumer Advocate | End User | Don Kries | Erin Camp (tel) | |
| New England Power Generators Assoc. (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 | Generation | | Pete Fuller | |
| Nylon Corporation of America (L) | End User | | | William P. Short III |
| 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 | |
| PNE Energy Supply | Supplier | | | William P. Short III |
| PowerOptions, Inc. | End User | Heather Tackle | | |
| Princeton Municipal Light Department | Publicly Owned Entity | | Brian Thomson | |
| 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 | |
| Saint Anselm College | End User | | | William P. Short III |
| Shrewsbury Electric & Cable Operations | Publicly Owned Entity | | Brian Thomson | |
| Small RG Group Member | AR-RG | Erik Abend (tel) | | |
| 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 | | | Peter 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 (tel) | Mary Smith (tel) | |
| 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 (tel) |
| Versant Power | Transmission | Lisa Martin (tel) | | |

## PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
## PARTICIPATING IN ~~NOV~~THE NOVEMBER 3, 2021 MEETING

| PARTICIPANT NAME | SECTOR/ GROUP | MEMBER NAME | ALTERNATE NAME | PROXY |
|---|---|---|---|---|
| Village of Hyde Park (VT) Electric Department | Publicly Owned Entity | | Dave Cavanaugh | |
| Vitol Inc. | Supplier | Joe Wadsworth (tel) | | |
| 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 | |
| Westfield Gas & Electric Department | Publicly Owned Entity | | Dave Cavanaugh | |
| Wheelabrator North Andover Inc. | AR-RG | | Bill Fowler | |
| Z-TECH, LLC | End User | | | William P. Short III |

# CONSENT AGENDA

## *Reliability Committee (RC)*

From the previously-circulated notice of actions of the RC's November 16, 2021 meeting, dated November 16, 2021.[1]

1. **Changes to Appendix D to OP 12 (Web-Based Submission; Remove "Option C" Resources)**

   Support revisions to Appendix D to ISO-NE Operating Procedure (OP) 12 (Voltage Schedule Annual Transmittal Form), to add a link for web-based submission versus past e-mail submissions and remove the "Option C" resources from the document per NPCC requirements, as recommended by the RC at its November 16, 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.

2. **Changes to OP-14 Appendices A & E (Periodic Review Changes)**

   Support revisions to Appendices A (Explanation of Terms and Instructions for Data Preparation of ISO-NE New England Form NX-12, Generator Technical Data) & E (Explanation of Terms and Instructions for Data Preparation of ISO New England Form NX-12E, Asset Related Demands Technical Data) to OP-14 (Technical Requirements for Generators, Demand Response Resources, Asset Related Demands and Alternative Technology Regulation Resources), including revisions to the explanation of Local Control Center (LCC) and edits to update language, definitions and correct typos, as recommended by the RC at its November 16, 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.

[1] RC Notices of Actions are posted on the ISO-NE website: https://www.iso-ne.com/static-assets/documents/2021/11/111621_rc_actions_letter.pdf

# Commissioner Clements

Commissioner Allison Clements has two decades of public and private sector experience in energy regulation and policy, representing utilities, independent power producers, developers and lenders, nonprofits and philanthropies on grid policy issues. Commissioner Clements is the founder and president of Goodgrid, LLC, an energy policy and strategy consulting firm. Previously she spent two years as director of the energy markets program at Energy Foundation. Prior to her time at Energy Foundation and Goodgrid, Commissioner Clements worked for a decade at Natural Resources Defense Council in New York, NY, as the organization's corporate counsel and then as director of the Sustainable FERC Project. Before that, Commissioner Clements spent several years in private legal practice, with the energy regulatory group at Troutman Sanders LLP (now Troutman Pepper) and then with the project finance and infrastructure group at Chadbourne & Parke LLP (now Norton Rose Fulbright).

Commissioner Clements has served as a federal energy expert in several capacities, including as a member of a National Academies of Sciences committee on grid resilience, as co-chair of the Bipartisan Policy Center's electric grid initiative, and as a clinical visiting lecturer at Yale Law School.

Commissioner Clements grew up in Dayton, Ohio. She has a Bachelor of Science from the University of Michigan and a Juris Doctorate from The George Washington University Law School.

**Sworn In**

December 8, 2020

**Term Expires**

June 30, 2024

**Follow on Social Media**

**Contact**

Telephone: 202-573-2699

Request a Meeting →

## Staff

**MILES FARMER**
Legal Advisor

**CAROL CLAYTON**
Legal Advisor

**BYRON CORUM**
Technical Advisor

**KRIS FITZPATRICK**
Technical Advisor

**ASHANTI WASHINGTON**
Confidential Assistant

**ALEXANDER DE TABOADA**
Special Assistant

## Tweets from @ClementsFERC

Tweets by https://twitter.com/ClementsFERC

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*This page was last updated on February 18, 2021*

**Summary of ISO New England Board and Committee Meetings**

**December 2, 2021 Participants Committee Meeting**

Since the last update, the Board of Directors met on November 1 and 2. The Audit and Finance Committee, the Compensation and Human Resources Committee, the Markets Committee, the Nominating and Governance Committee, and the System Planning and Reliability Committee each met on November 2. All of the meetings were held in person in Boston. In addition, the Audit and Finance Committee met virtually on November 10.

On November 2, **the Audit and Finance Committee** held an executive session to discuss corporate goals for 2022. The Committee then reviewed and approved the unaudited financial statements for the third quarter after receiving a report on the related disclosure control process. Next, the Committee met with representatives of KPMG, the Company's external auditors, to discuss the scope and preliminary results of the 2021 System and Organization Controls Report and resulting unqualified audit opinion. KPMG also provided an overview of work plans and timing for the financial statements audit. The Committee then met with the KPMG auditors in executive session.

At its meeting on November 10, the Committee received an annual report on employee and Board code of conduct compliance following the annual collection of certificates, and an update on the Company's use of EthicsPoint, an internet- and telephone-based anonymous reporting tool. The Committee was also provided with a report on current budget performance along with an update on interest rates. Next, the Committee met with representatives from Meyers Brothers Kalicka, the Company's external benefit plan auditors, to discuss the favorable results of employee benefit plan audits. The Committee also discussed Department of Labor reporting requirements related to the Company's severance plan. The Committee then received a report on internal audit activities, including a report on follow-up items related to internal reviews and the oversight of external audits. Finally, the Committee reviewed its calendar for the upcoming year.

**The Compensation and Human Resources Committee** discussed key dates and deliverables for 2022 goal setting and corporate performance review for 2021, and reviewed its calendar for the upcoming year. Next, the Committee received an update on the Company's efforts on diversity, equity and inclusion, including the work of the newly-formed employee Council for Diversity and Inclusion. Members of the Council joined the meeting to report on different initiatives. The Committee also received an update on management's plans for the workforce to return to the office on January 4, 2022, as well as the requirement for all employees to be fully vaccinated as a condition of continued employment. The Committee then received an update on Department of Labor reporting requirements related to the Company's severance plan. During an executive session, the Committee reviewed executive and board compensation survey data.

**The Markets Committee** was provided with a summary of market performance for the 2021 summer season from the internal and external market monitors. The Committee also discussed the factors that may influence energy prices for the winter of 2022-2023. Next, the Committee discussed activities related to the initiative to eliminate the Minimum Offer Price Rule (MOPR) in the Forward Capacity Market, and received an overview of the Company's proposal to address buyer-side market power, and a summary of ongoing discussions with stakeholders, including a stakeholder proposal to adopt a transition period before the elimination of the MOPR. The Committee then reviewed its calendar for the upcoming year and held an executive session to discuss corporate goals for 2022.

**The Nominating and Governance Committee** discussed ongoing director education, including possible site visits for later in 2022 and potential guest speakers to meet virtually with the Board. The Committee also received an update on Joint Nominating Committee activities. The Committee discussed best practices regarding Board diversity and inclusion initiatives, and agreed to consider utilizing a matrix to track Board diversity similar to one used by NASDAQ. The Committee also considered revisions to its charter to specify the Committee's responsibility to ensure a diverse board, and agreed to recommend those changes to the Board for approval at a future meeting. Finally, the Committee reviewed its calendar for the upcoming year.

**The System Planning and Reliability Committee** reviewed summer operations for 2021. The Committee received updates on various operations and planning activities, including regional planning, qualification results for Forward Capacity Auction #16, and economic studies and special study results. The Committee also reviewed key operations and planning metrics, as well as reliability standards compliance, and was informed of updates to Regional System Plan projects. The Committee then reviewed its calendar for the upcoming year and held an executive session to discuss corporate goals for 2022.

**The Board of Directors** received a report from the CEO, including a quarterly update on goal achievement. The Board also received a report on the current outlook for the 2021-2022 winter, and discussed the capacity analysis, load forecast, and fuel risks in New England. The Board then prepared for its meeting with state representatives and reviewed topics proposed for discussion, including governance, winter operations, preparedness for extreme weather events, the continuing need to address energy security, and the elimination of the Minimum Offer Price Rule. The Board held its annual strategic planning and risk management review, and discussed the Company's overarching risks, mitigation strategies, and goals. The Board then met with state representatives.

The next day, the Board continued its meeting and prepared for upcoming sessions with the NEPOOL sectors by reviewing the subjects submitted for discussion. The Board heard reports from the standing committees. During the System Planning and Reliability Committee report, the Board approved the 2021 Regional System Plan. During the Compensation and Human Resources Committee report, the Board approved conforming edits to the Committee's charter regarding previously-approved changes in the Company's retirement and welfare plan investment fiduciary. The Board held an executive session, and discussed the Board Chair transition.

# NEPOOL Participants Committee Report

*December 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: October 2021 Energy Market value totaled $560M
  - November Energy market value over the period was $375M, down $185M from October 2021 and up $130M from November 2020
    - November natural gas prices over the period were 6.1% higher than October average values
    - Average RT Hub Locational Marginal Prices ($52.22/MWh) over the period were 6.6% lower than October averages
      - DA Hub: $52.03/MWh
    - Average November 2021 natural gas prices and RT Hub LMPs over the period were up 154% and 112%, respectively, from the same month last year
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 98.6% during November, down from 99% during October*
    - The minimum value for the month was 93.9% on November 22nd**

**All data through November 22nd**

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

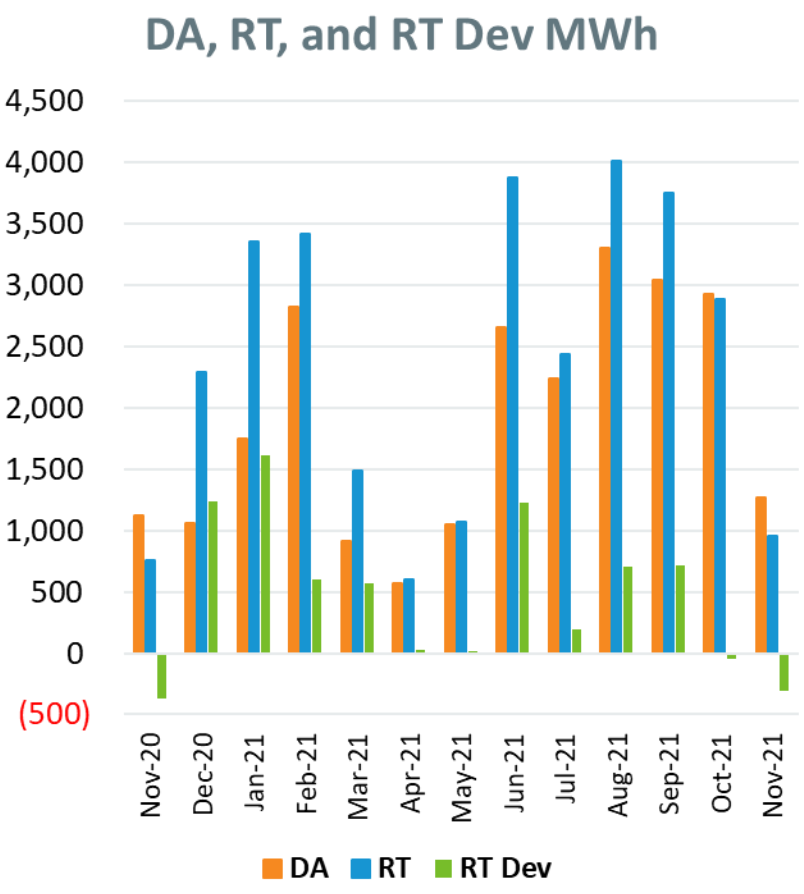
Underlying natural gas data furnished by: ICE Global markets in clear view

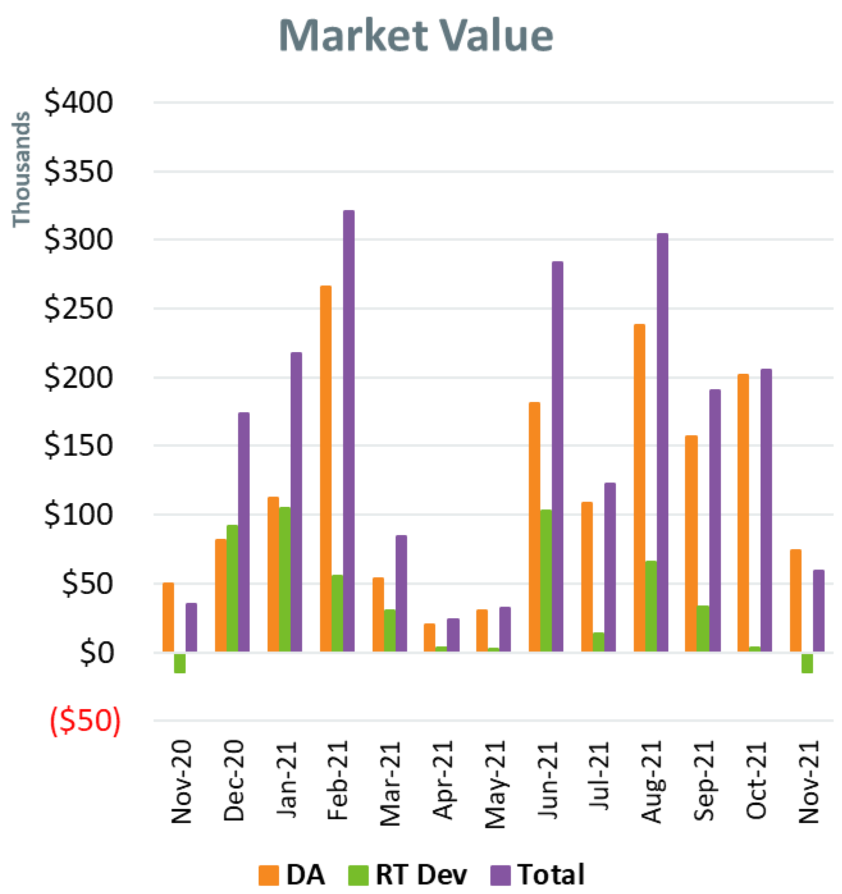
# Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - November NCPC payments totaled $2.5M over the period, down $1M from October and up $0.6M from November 2020
    - First Contingency payments totaled $2.2M, down $0.7M from October
      - $2.1M paid to internal resources, down $0.3M from October
        - » $302K charged to DALO, $571K to RT Deviations, $1.3M to RTLO*
      - $4K paid to resources at external locations, down $430K from October
        - » Charged to RT Deviations
    - Second Contingency payments totaled $177K, down $494K from October
      - Charged to Eastern Reliability Regions
    - Voltage payments totaled $210K, up $210K from October
      - Low voltage support required during transmission work early in the month
  - NCPC payments over the period as percent of Energy Market value were 0.7%

*** NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $225K; Rapid Response Pricing (RRP) Opportunity Cost - $164K; Posturing - $0K; Generator Performance Auditing (GPA) - $888K**

# 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

- Additional ancillary services and initial resource adequacy screen results for the 2021 Economic Study (Future Grid Reliability Study) were discussed at the November 17 PAC meeting
  - The ISO will seek feedback from the MC/RC at the December 15 meeting for the high-level transmission, ancillary services, and resource adequacy screen analyses
- Both the ICR and Informational (qualification) FERC filings were made on November 9
- ICR and Related Values for 2022 ARAs will be filed with FERC by November 30
- Attachment K Resources FERC filing was made on November 12
- Transmission Planning for the Clean Energy Transition report on the pilot study is expected to be released by the end of the year

# Highlights

- NERC GridEx VI was conducted on November 16 and 17
- The ISO was the planner for this exercise in New England, and the two day exercise was conducted with active participation from the local control centers
- A report highlighting key takeaways and lessons learnt is being compiled, and the ISO will share those highlights with stakeholders in early 2022

# 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
  - ARA3 will be held in March 2022
  - ICR and Related Values to be filed with FERC by November 30
- CCP 14 (2023-2024)
  - First annual reconfiguration auction (ARA1) was held on June 1-3, and results were posted June 30
  - ARA2 will be held in August 2022
  - ICR and Related Values to be filed with FERC by November 30

CCP – Capacity Commitment Period

# FCM Highlights, cont.

- CCP 15 (2024-2025)
  - Auction results were approved on June 24
  - ARA1 will be held in June 2022
  - ICR and Related Values to be filed with FERC by November 30
- 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
  - Both the ICR and Informational (qualification) FERC filings were made on November 9
  - Preparations are ongoing for the auction that will commence on February 7

# FCM Highlights, cont.

- CCP 17 (2026-2027)
  - The qualification process has started, and training materials are under development
  - Topology certifications were sent to the TOs on October 2
    - TOs to identify in-service dates for new transmission projects and revisions to previously certified projects
    - Approved projects to be shared with the RC at their January 2022 meeting
  - Capacity zone development discussions began at the November 17 PAC meeting
    - All subsequent reconfiguration auctions model the same zones as the FCA

# 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
- Upcoming Meetings
  - Load Forecast Committee Meeting will be held on December 10
  - Both the Energy-Efficiency Forecast Working Group (EEFWG) and Distributed Generation Forecast Working Group (DGFWG) will meet on December 6

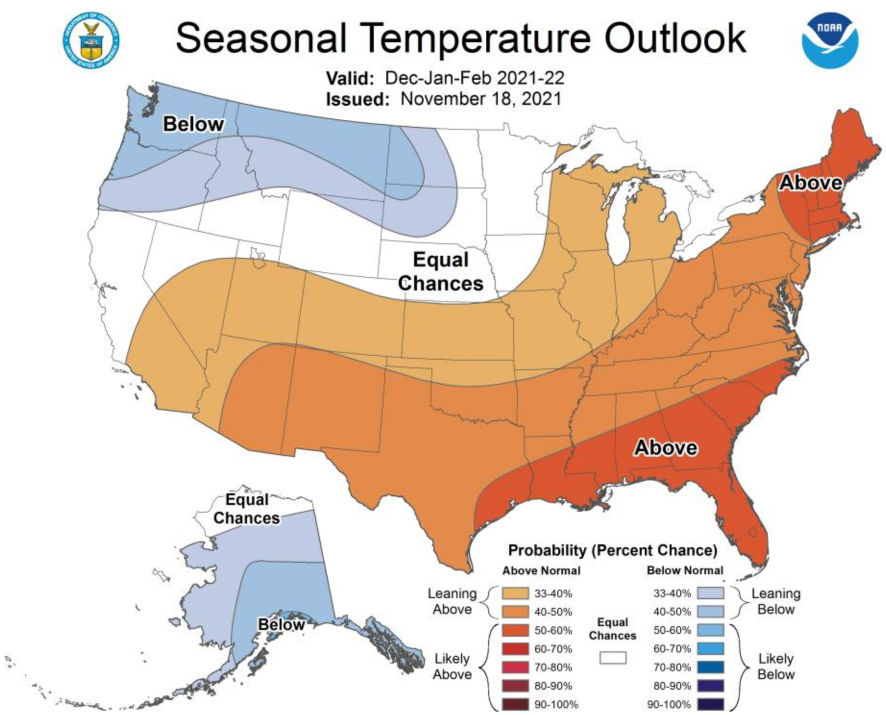
# Highlights

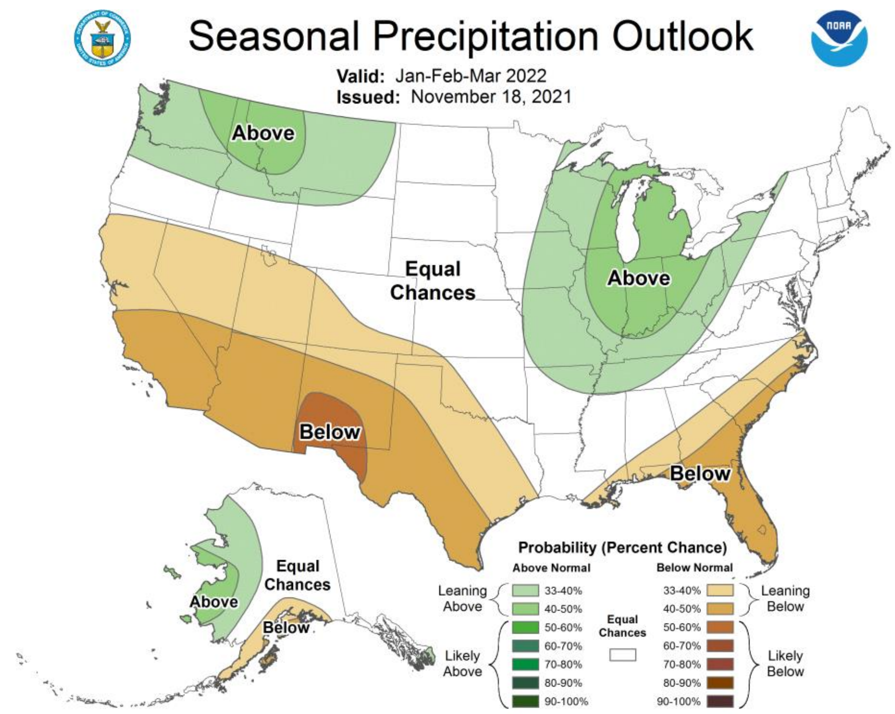
- The lowest 50/50 and 90/10 Winter Operable Capacity Margins are projected for week beginning January 8, 2022.

# New England Winter Outlook 2021/2022

# Winter Outlook – Weather Update

- Latest 90 day NOAA weather outlook (11/18/21) still indicates a 40-50% probability of above normal temperatures for all of New England and an equal chance for above average or below average precipitation for the winter months of December – January - February



# Winter Outlook – Fuel Price and Inventory Update

- Gas Prices for January Delivery as of 11/29 are:
  - European Gas/LNG at ~$29
  - Asian Gas/LNG at ~$35
  - Algonquin/New England at ~$19.00
- Oil inventories for New England Generators have increased slightly to 53% from 51% capacity with limited new quantities expected at this time
  - Inventory graphs are available at the following link
  - https://www.iso-ne.com/static-assets/documents/2021/11/2021-11-23_oil_inventory_graphs.pdf
  - Oil depletion charts are available at the following link
  - https://www.iso-ne.com/static-assets/documents/2021/11/2021-11-23_oil_depletion_graphs.pdf

# Winter Expectations 2021-2022

- Winter Demand Forecast
  - 50/50 winter peak demand forecast of 19,710 MW, which is 456 MW (2.3%) lower than the 2020-21 forecast
  - 90/10 winter peak demand forecast of 20,349 MW, which is 457 MW (2.2%) lower than the 2020-21 forecast
- Scheduled Generation and Transmission Outages
  - All generation and transmission outages continue to be coordinated to minimize adverse transmission or capacity conditions
  - No significant generation or transmission outages are currently scheduled
- Transfer Capability
  - Transfer capability on the New York Northern AC ties will be increased from 1,400 to 1,600 MW for the winter period

# High Level Winter Assessment

- If the 2021/22 winter profile is similar to that of winter 2020/21, the ISO anticipates that the system can be operated reliably without the need for emergency procedures
  - Assumes no significant generation or transmission outages and limited fuel replenishment
- Winter 2020/21 was mild with the following characteristics:
  - Milder than normal with a few short periods of below normal temperatures
  - Average temperature departure from normal was +1.8°F degrees
  - Winter peak load of 18,756 MW
  - Natural gas was available as needed, fuel oil usage was minimal and fuel supplies remained steady
  - The total energy served during this period was 32,188 GWh

# High Level Winter Assessment, cont’d.

- If the 2021/22 winter profile is similar to that of winter 2017/18, the ISO anticipates that the system can be operated reliably, but may require the implementation of capacity deficiency procedures
  - Assumes no significant generation or transmission outages and limited fuel replenishment
- If the region has adequate fuel replenishment, the ISO anticipates that the system can be operated reliably without the need for emergency procedures
- Winter 2017/18 was milder than normal, except for a long cold spell, and with the following characteristics:
  - Milder than normal except for a two-week span of significantly below normal temperatures
  - Average temperature departure from normal was +0.5°F degrees
  - The region was impacted by an extended stretch of cold weather from December 25 through January 8; All major cities in New England experienced temperatures below normal for at least 13 consecutive days, of which 10 days averaged more than 10°F below normal
  - Winter peak load of 20,631 MW
  - The cold snap was marked by significant reductions in natural gas availability and price inversion contributed to high oil usage; several oil-fired resources were postured to maintain fuel reserves.
  - The total energy served during this period was 33,186 GWh

# High Level Winter Assessment, cont'd

- If the 2021/22 winter profile is similar to that of winter 2013/14 with persistent below normal temperatures and several cold stretches, the ISO anticipates that it may require the implementation of all available emergency procedures
  - Assumes no significant generation or transmission outages and limited fuel replenishment
- If the region has adequate fuel replenishment, the ISO anticipates that the system can be operated reliably without the need for emergency procedures
- Winter 2013/14 characteristics:
  - Colder than normal and highlighted by a polar vortex event with significant stretches of cold weather in New England and surrounding regions
  - Average temperature departure from normal was -2.3°F degrees
  - The region experienced several cold weather stretches of four or more consecutive days, including a stretch of ten consecutive days at or below freezing
  - Winter peak load of 21,514 MW
  - High demand on both the electric and natural gas systems
  - The total energy served during this period was 35,509 GWh

# SYSTEM OPERATIONS

# System Operations

| | | | | |
|---|---|---|---|---|
| **Weather Patterns** | Boston | Temperature: Above Normal (0.4°F)<br>Max: 70°F, Min: 27°F<br>Precipitation: 2.05" – Below Normal<br>Normal: 3.39"<br>Snow: 0.01" | Hartford | Temperature: Below Normal (0.4°F)<br>Max: 70°F, Min: 22°F<br>Precipitation: 1.29" - Below Normal<br>Normal: 3.24"<br>Snow: 0.01" |

| | | | |
|---|---|---|---|
| **Peak Load:** | 16,416 MW | November 23, 2021 | 18:00 (ending) |

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

| Procedure | Declared | Cancelled | Note |
|---|---|---|---|
| None for November 2021 | | | |

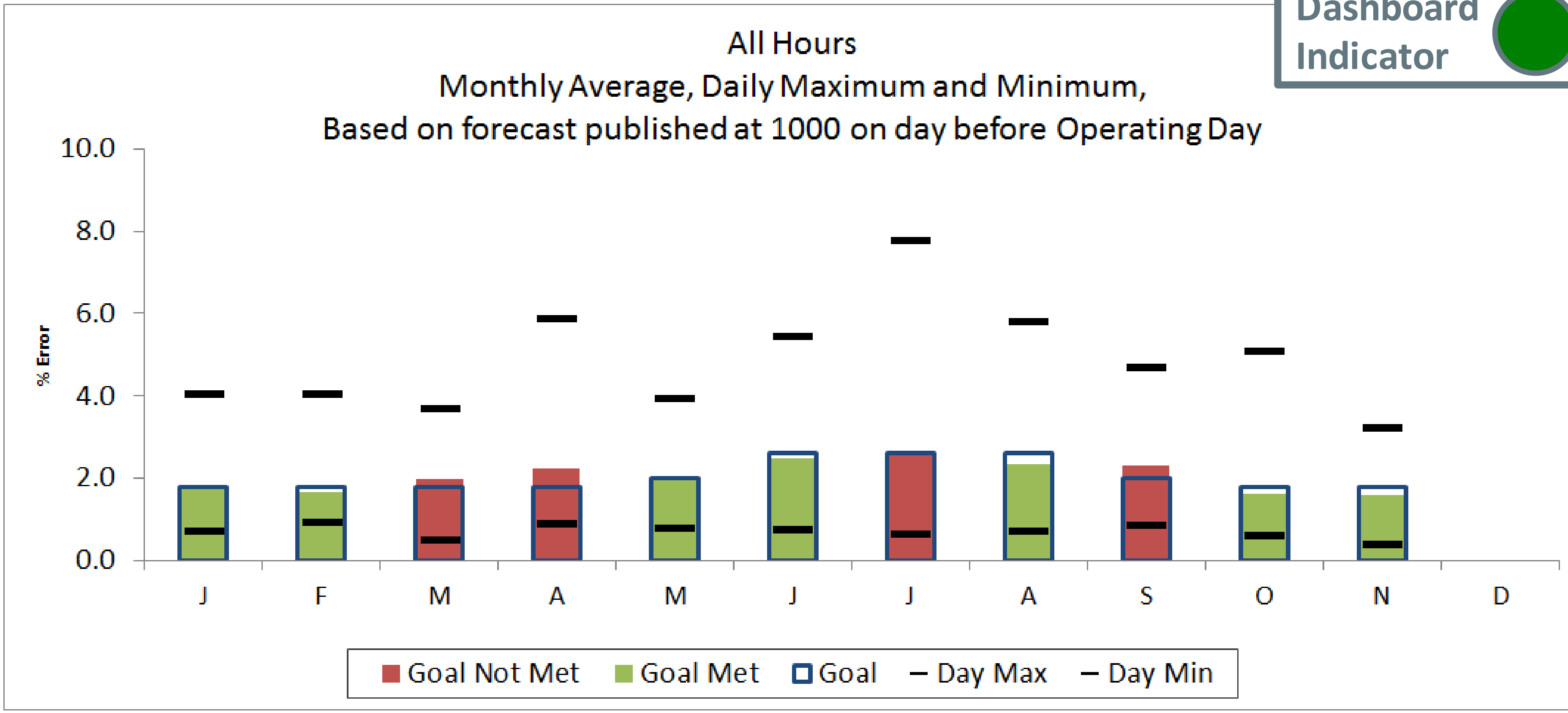
# System Operations

## NPCC Simultaneous Activation of Reserve Events

| Date | Area | MW Lost |
|---|---|---|
| 11/5 | IESO | 800 |

# 2021 System Operations - Load Forecast Accuracy

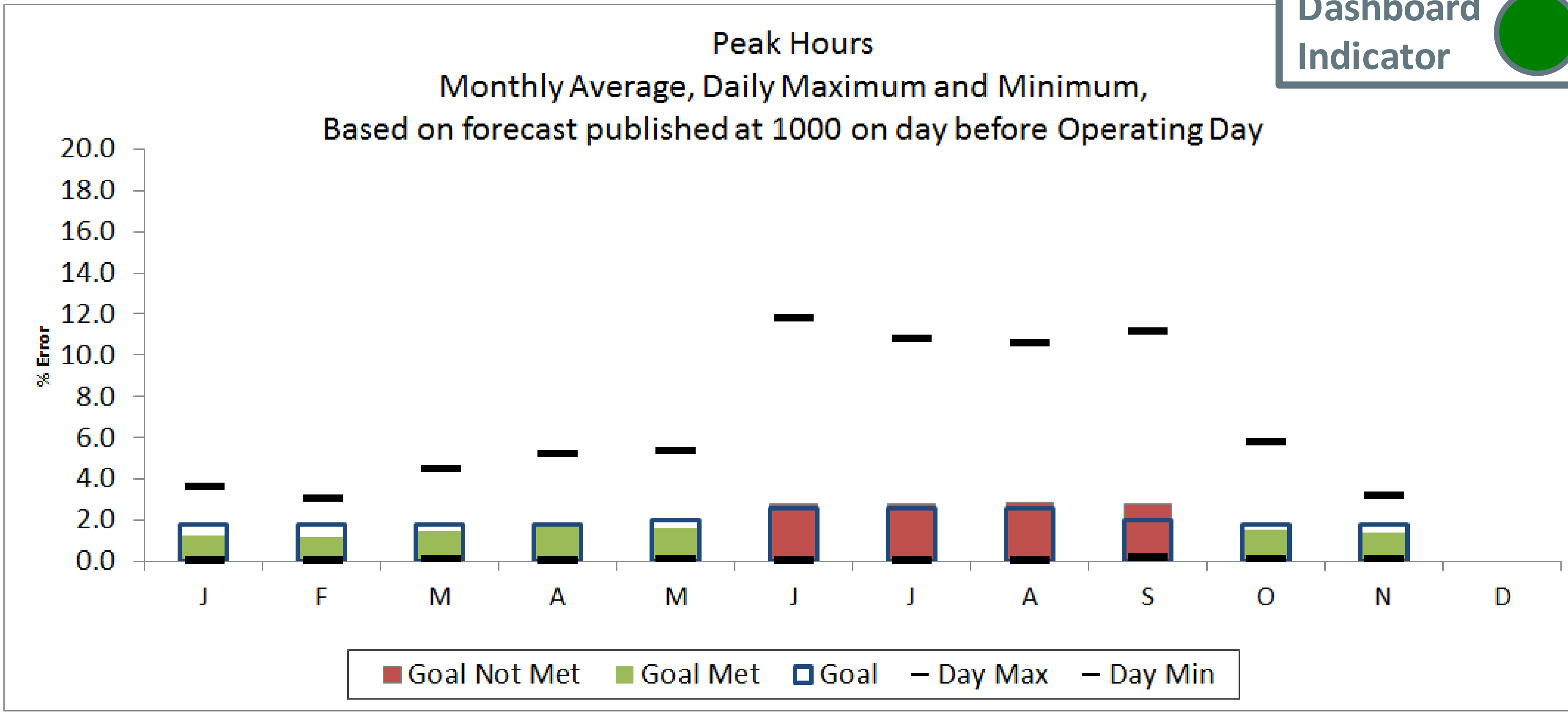
Dashboard Indicator




| 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 | 5.08 | 3.21 | | 7.75 |
| Day Min | 0.70 | 0.92 | 0.49 | 0.88 | 0.77 | 0.73 | 0.63 | 0.71 | 0.86 | 0.60 | 0.36 | | 0.36 |
| MAPE | 1.72 | 1.66 | 1.97 | 2.24 | 1.95 | 2.50 | 2.61 | 2.33 | 2.30 | 1.62 | 1.58 | | 2.05 |
| Goal | 1.80 | 1.80 | 1.80 | 1.80 | 2.00 | 2.60 | 2.60 | 2.60 | 2.00 | 1.80 | 1.80 | | |

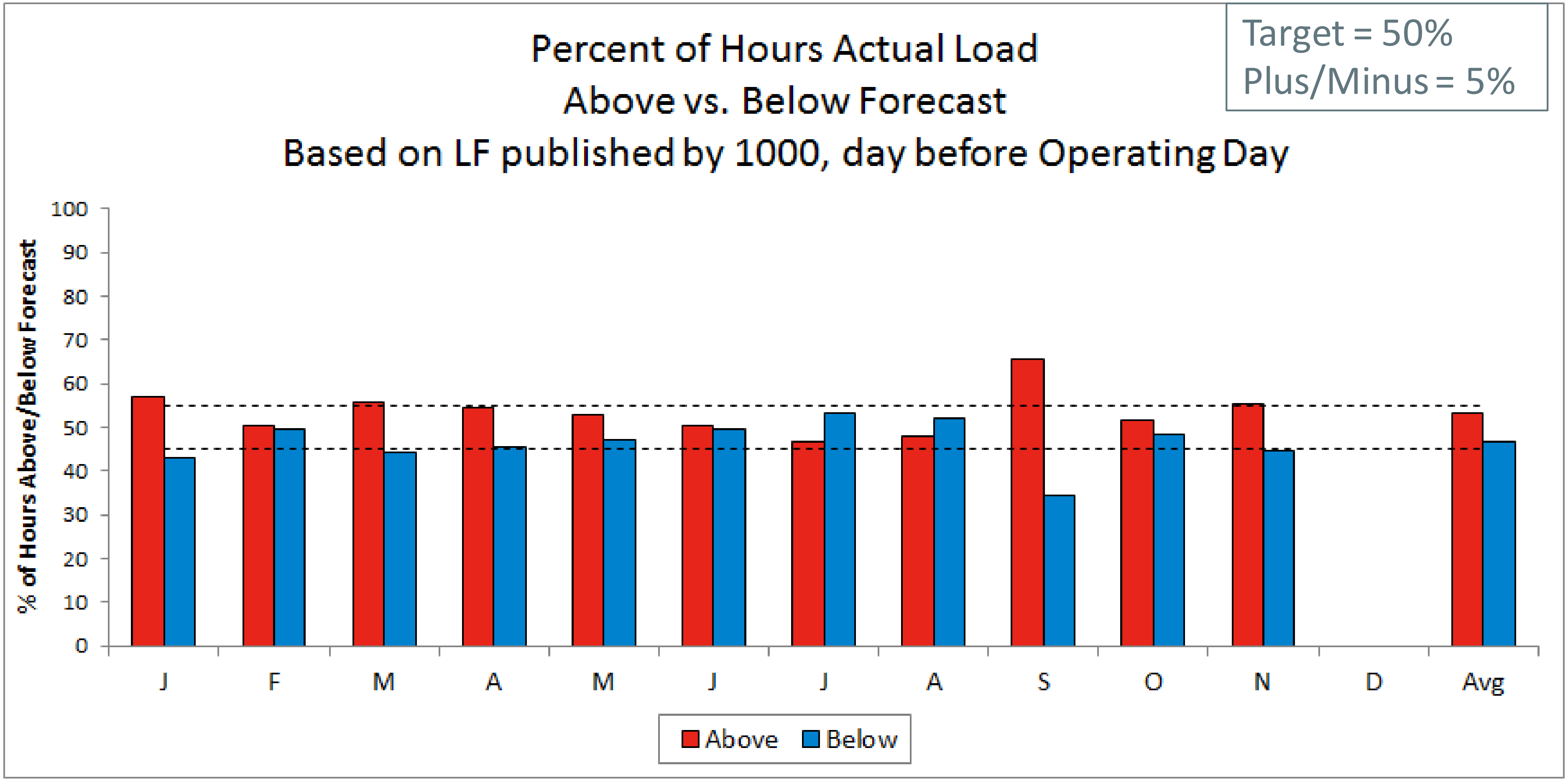
# 2021 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



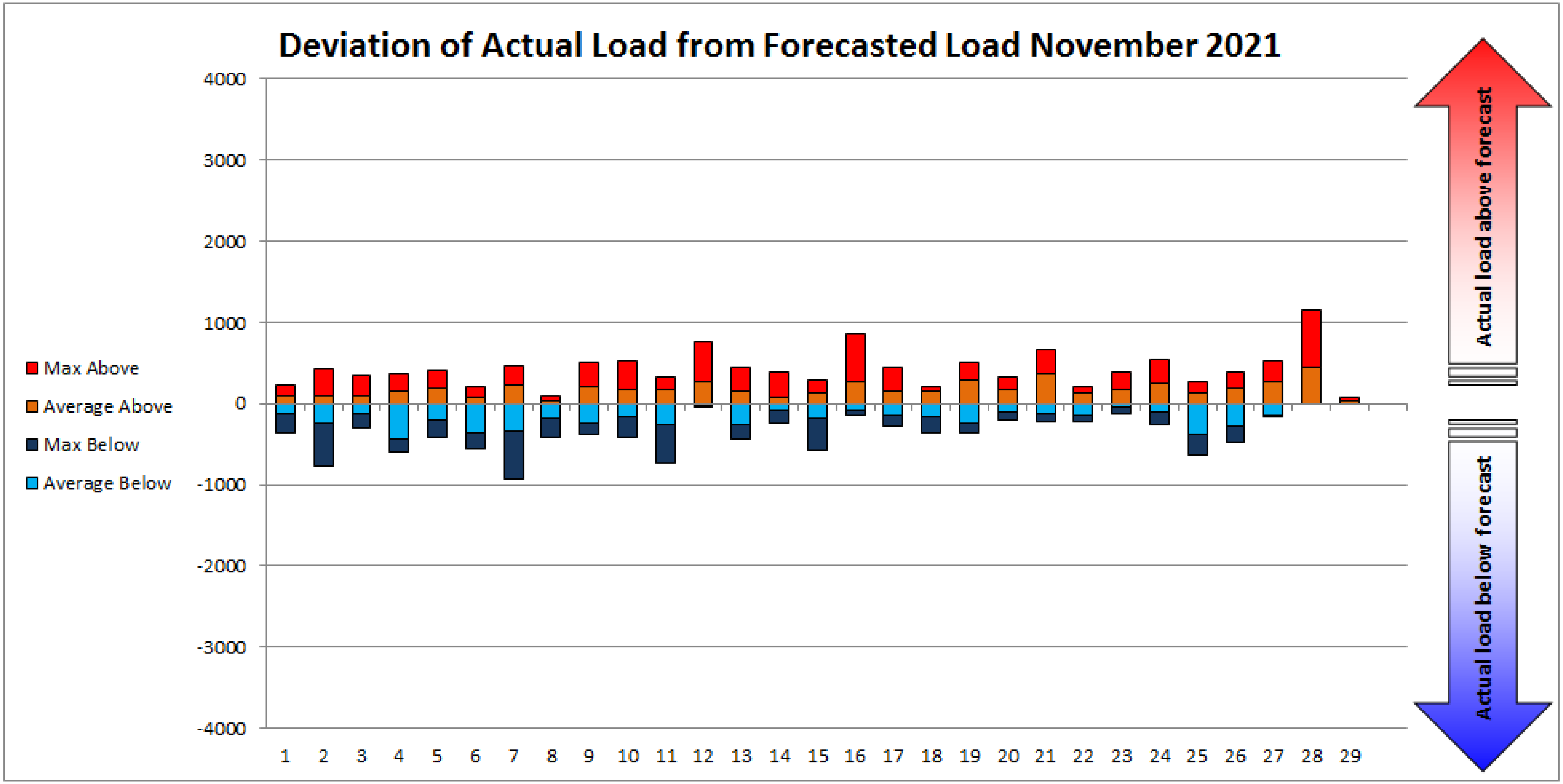

| Month | J | F | M | A | M | J | J | A | S | O | N | D | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Day Max | 3.61 | 3.03 | 4.47 | 5.19 | 5.31 | 11.76 | 10.75 | 10.54 | 11.13 | 5.79 | 3.17 | | 11.76 |
| Day Min | 0.02 | 0.06 | 0.08 | 0.03 | 0.11 | 0.04 | 0.05 | 0.01 | 0.17 | 0.09 | 0.12 | | 0.01 |
| MAPE | 1.26 | 1.18 | 1.48 | 1.66 | 1.60 | 2.79 | 2.78 | 2.86 | 2.76 | 1.51 | 1.37 | | 1.94 |
| Goal | 1.80 | 1.80 | 1.80 | 1.80 | 2.00 | 2.60 | 2.60 | 2.60 | 2.00 | 1.80 | 1.80 | | |

# 2021 System Operations - Load Forecast Accuracy cont.

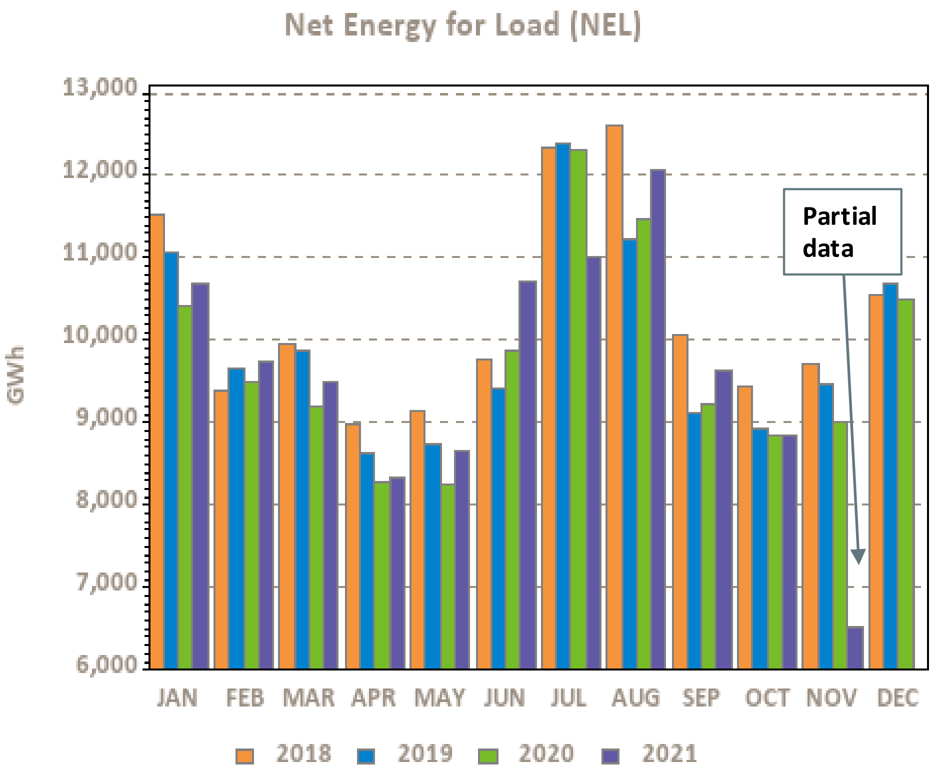



| | J | F | M | A | M | J | J | A | S | O | N | D | Avg |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Above % | 57.1 | 50.4 | 55.6 | 54.4 | 52.8 | 50.3 | 46.9 | 47.8 | 65.4 | 51.7 | 55.3 | | 53 |
| Below % | 42.9 | 49.6 | 44.4 | 45.6 | 47.2 | 49.7 | 53.1 | 52.2 | 34.6 | 48.3 | 44.7 | | 47 |
| Avg Above | 209.5 | 166.7 | 185.4 | 206.1 | 227.4 | 233.1 | 214.5 | 227 | 263.1 | 115.6 | 171.2 | | 263 |
| Avg Below | -147.6 | -216.4 | -188.0 | -167.9 | -146.8 | -309.1 | -348.1 | -307.5 | -196.2 | -173.4 | -173.1 | | -348 |
| Avg All | 60 | -25 | 30 | 40 | 61 | -48 | -122 | -79 | 102 | -31 | 16 | | 0 |

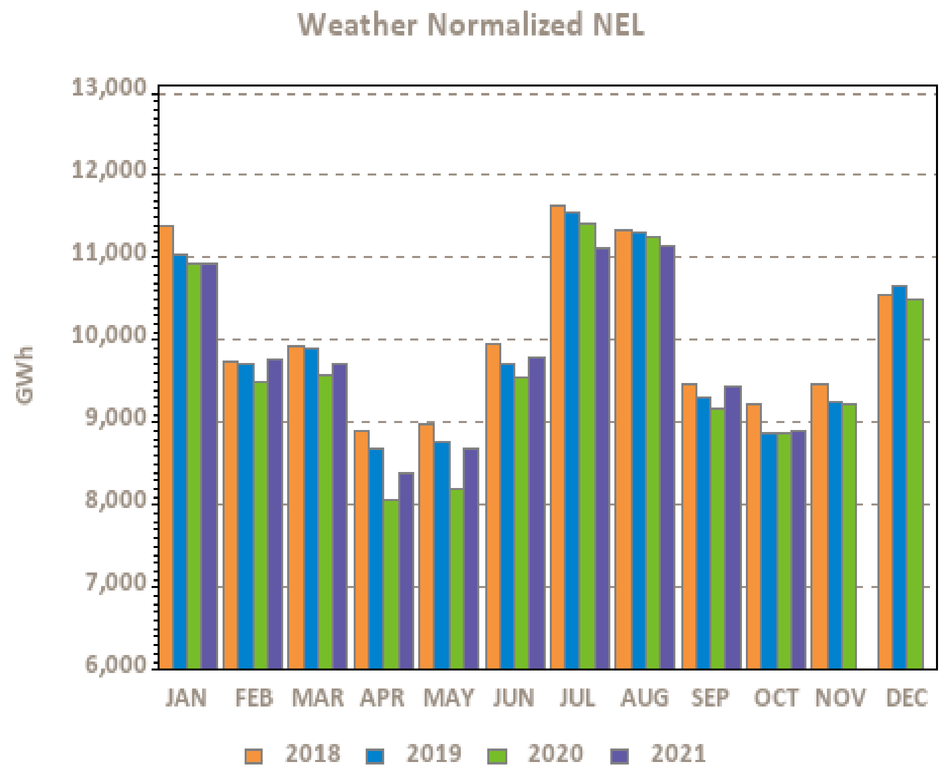
# 2021 System Operations - Load Forecast Accuracy cont.



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



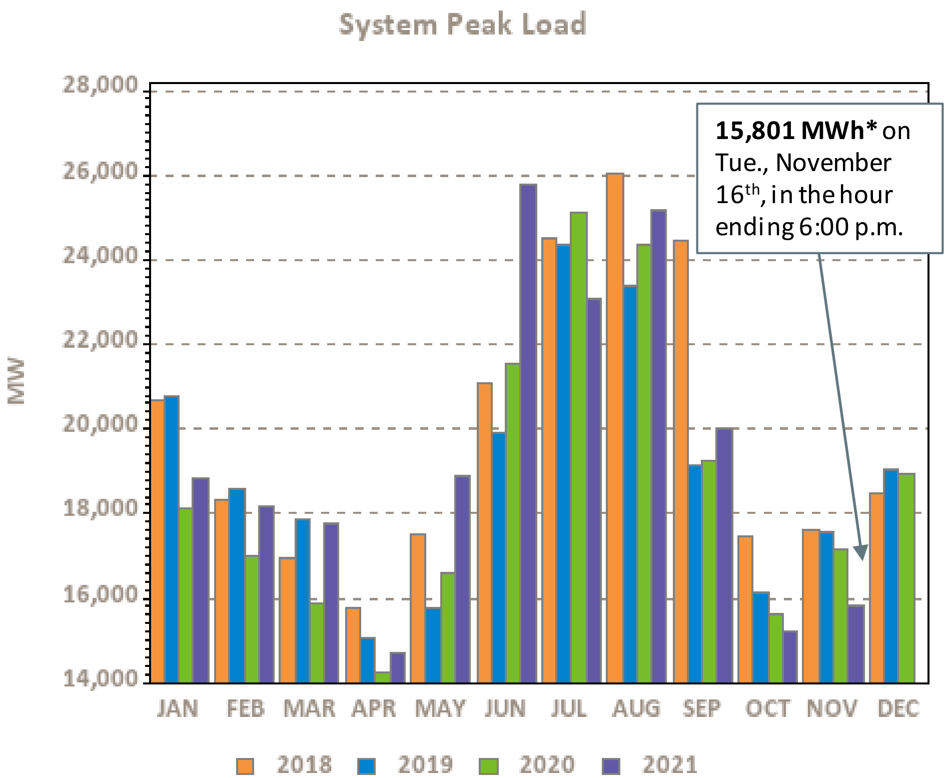

Ann Tot (TWh): 123.5 119.2 116.9 105.7



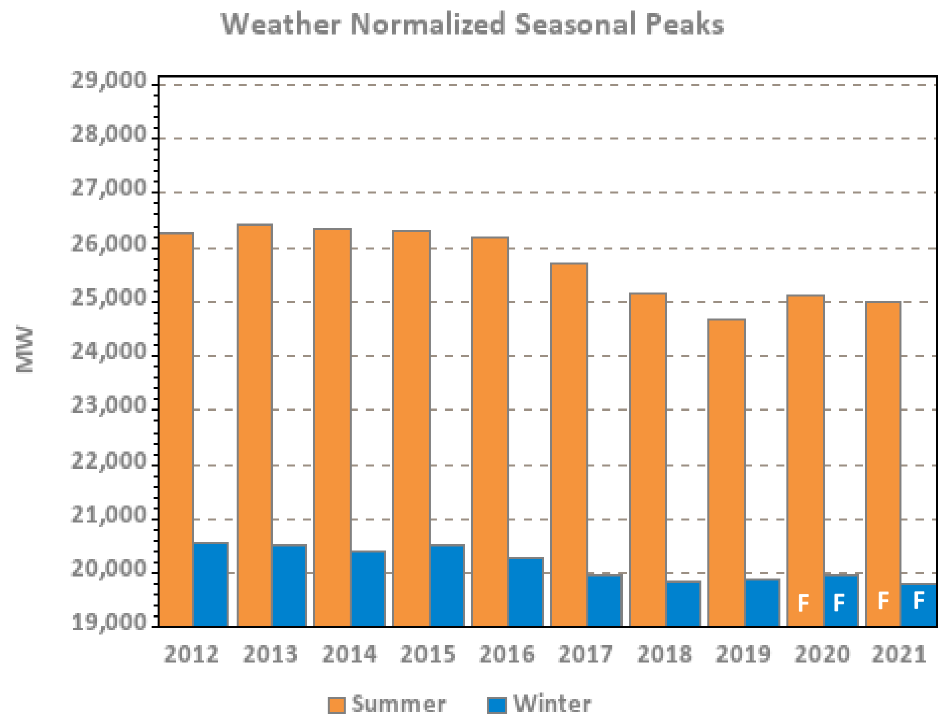

Ann Tot (TWh): 120.6 118.8 116.3 97.9

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

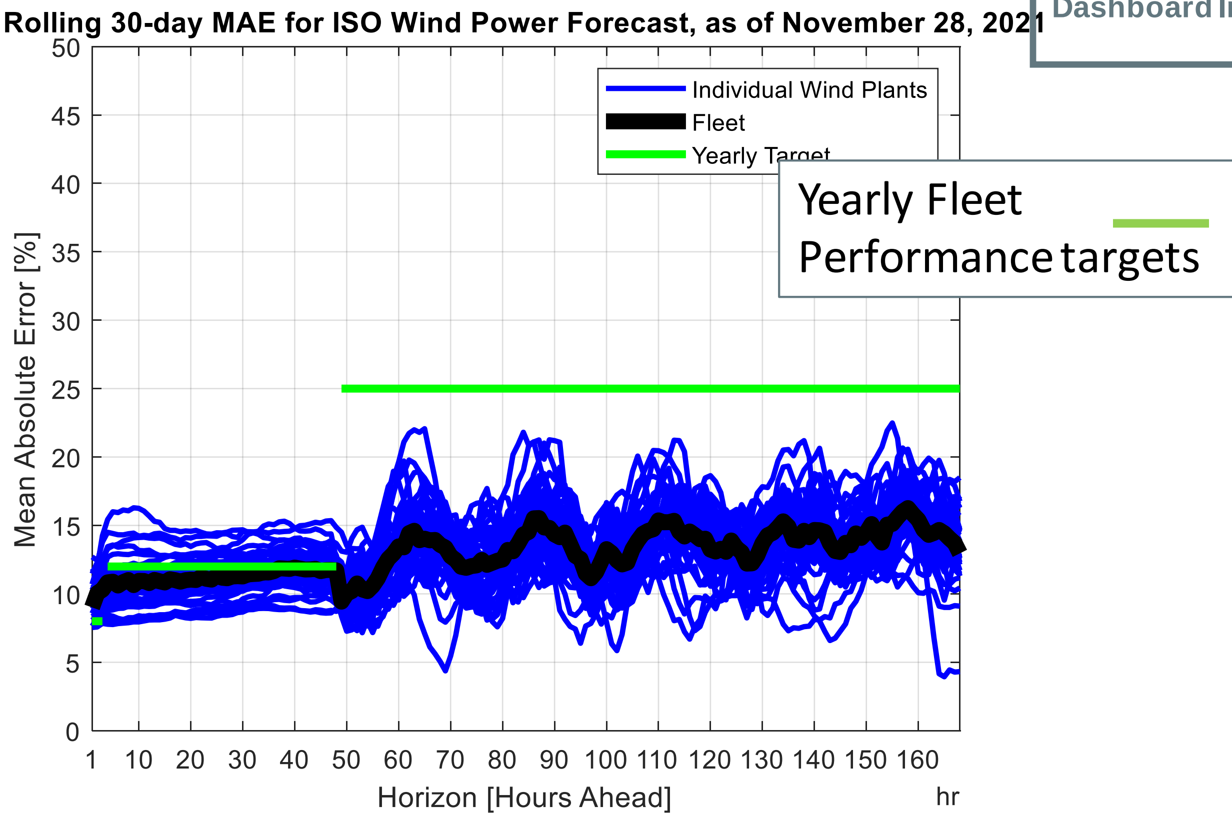



Winter beginning in year displayed

**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

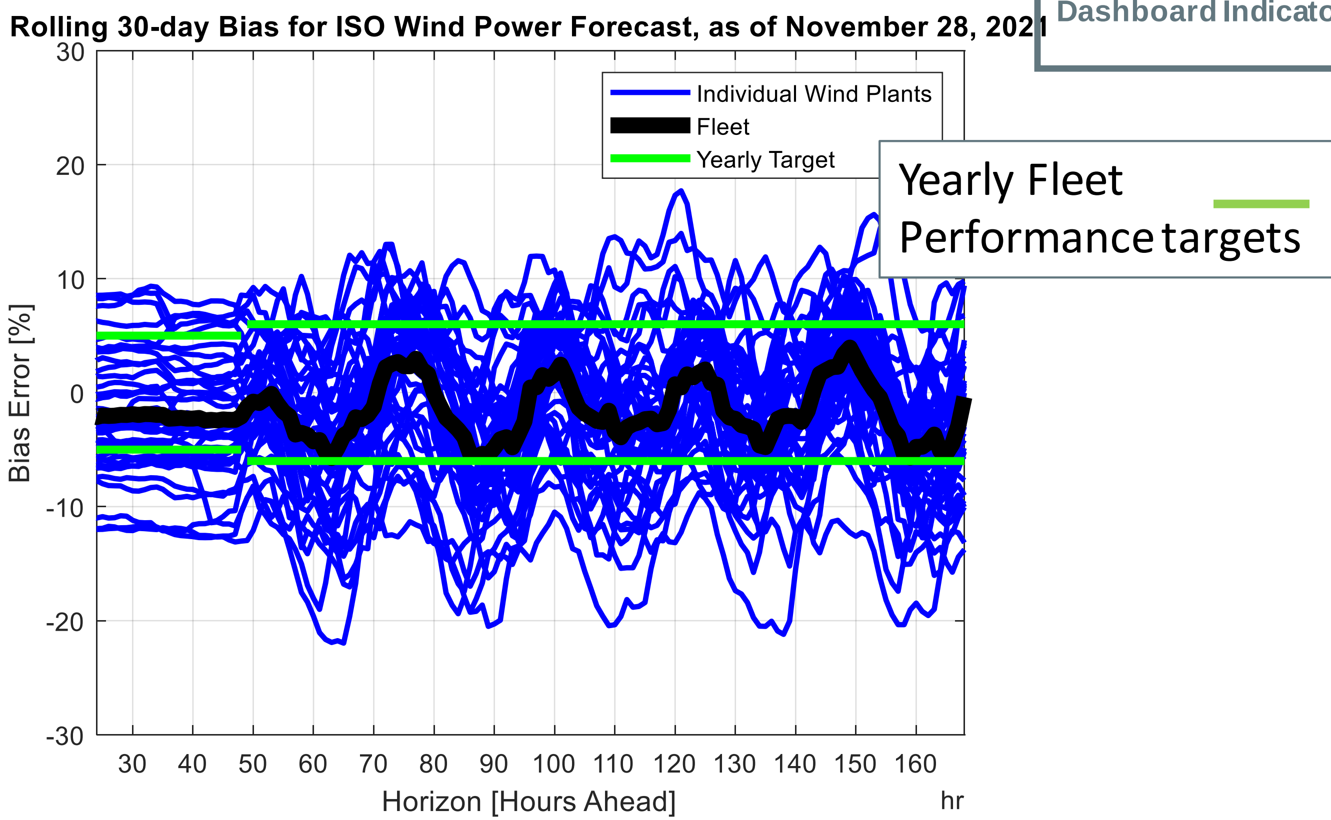
Dashboard Indicator




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 (with the exception of the first hour of look ahead) is within the yearly performance targets.

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

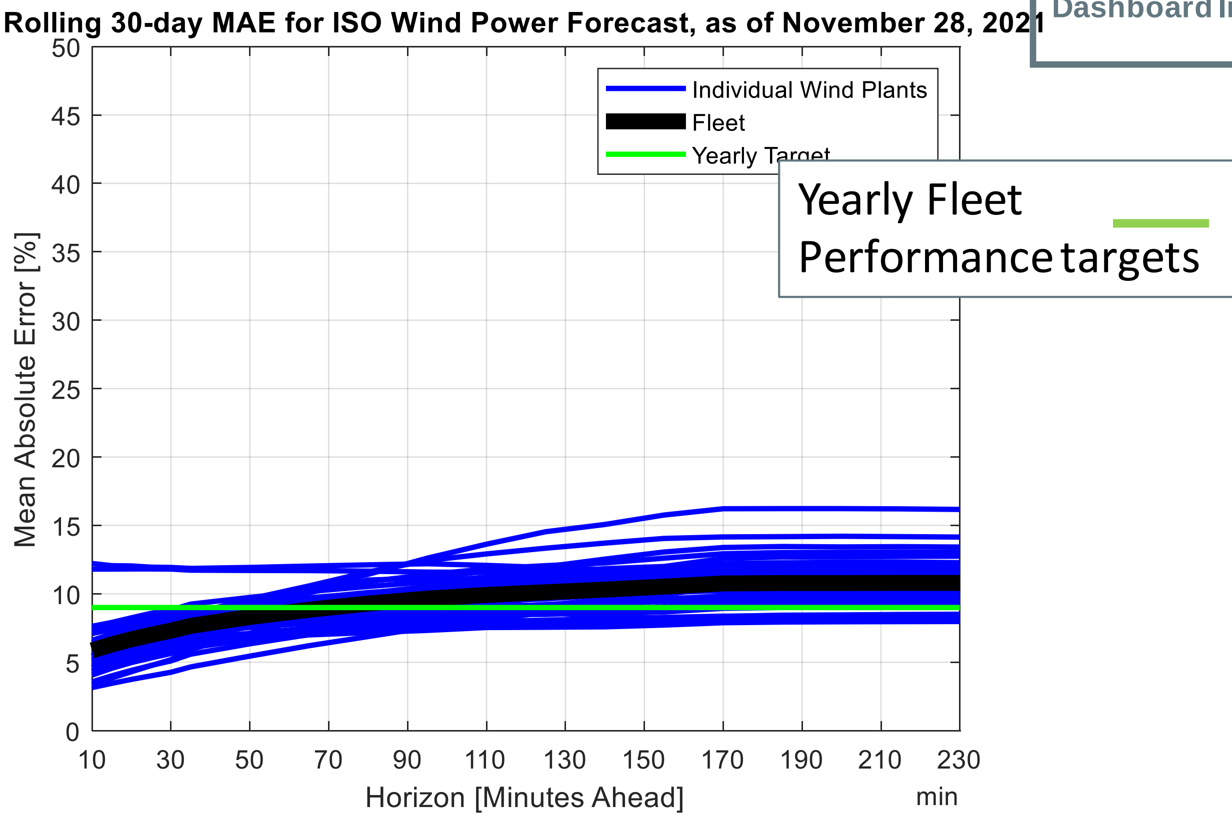
Dashboard Indicator




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

# Wind Power Forecast Error Statistics: Short Term Forecast MAE

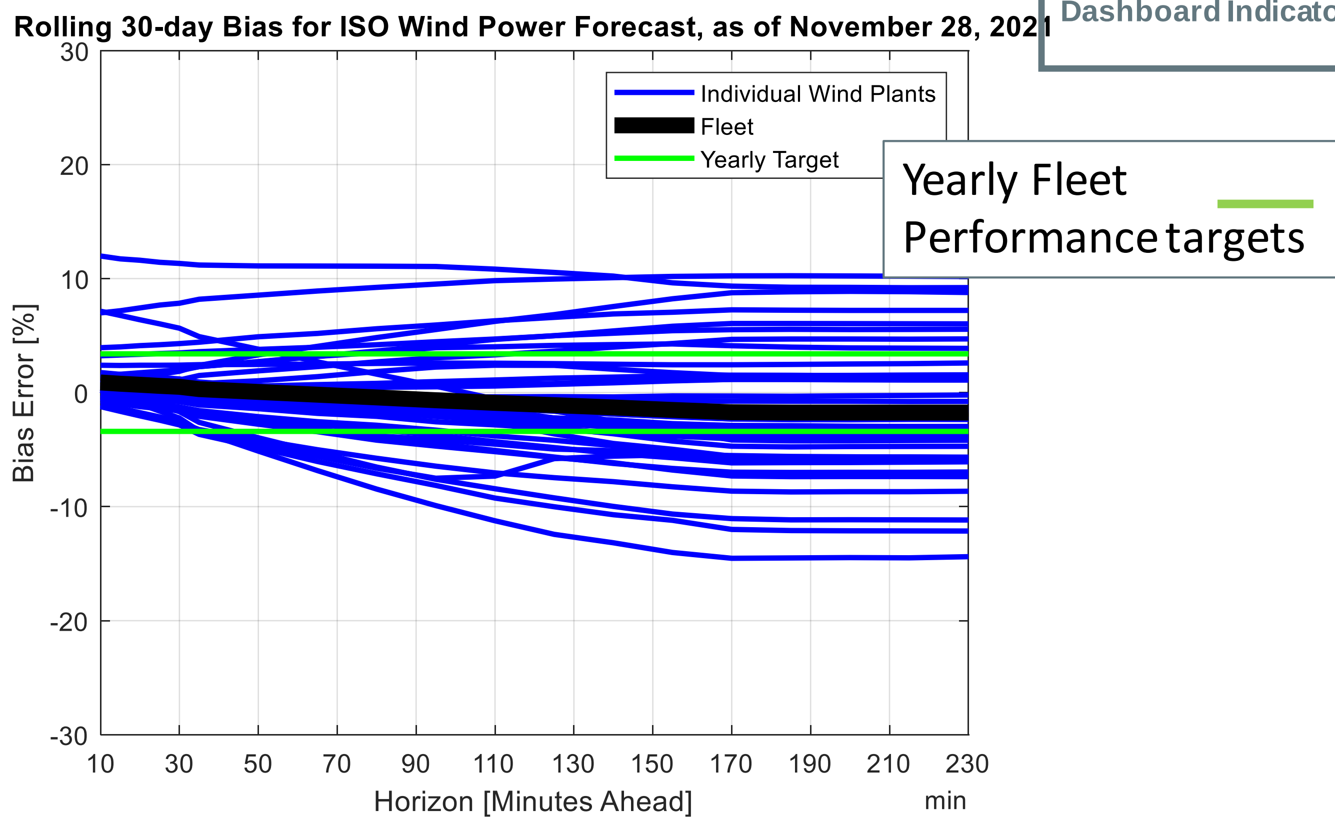
Dashboard Indicator




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 up to 90 minutes look-ahead monthly MAE is within the yearly performance targets.

# Wind Power Forecast Error Statistics: Short Term Forecast Bias

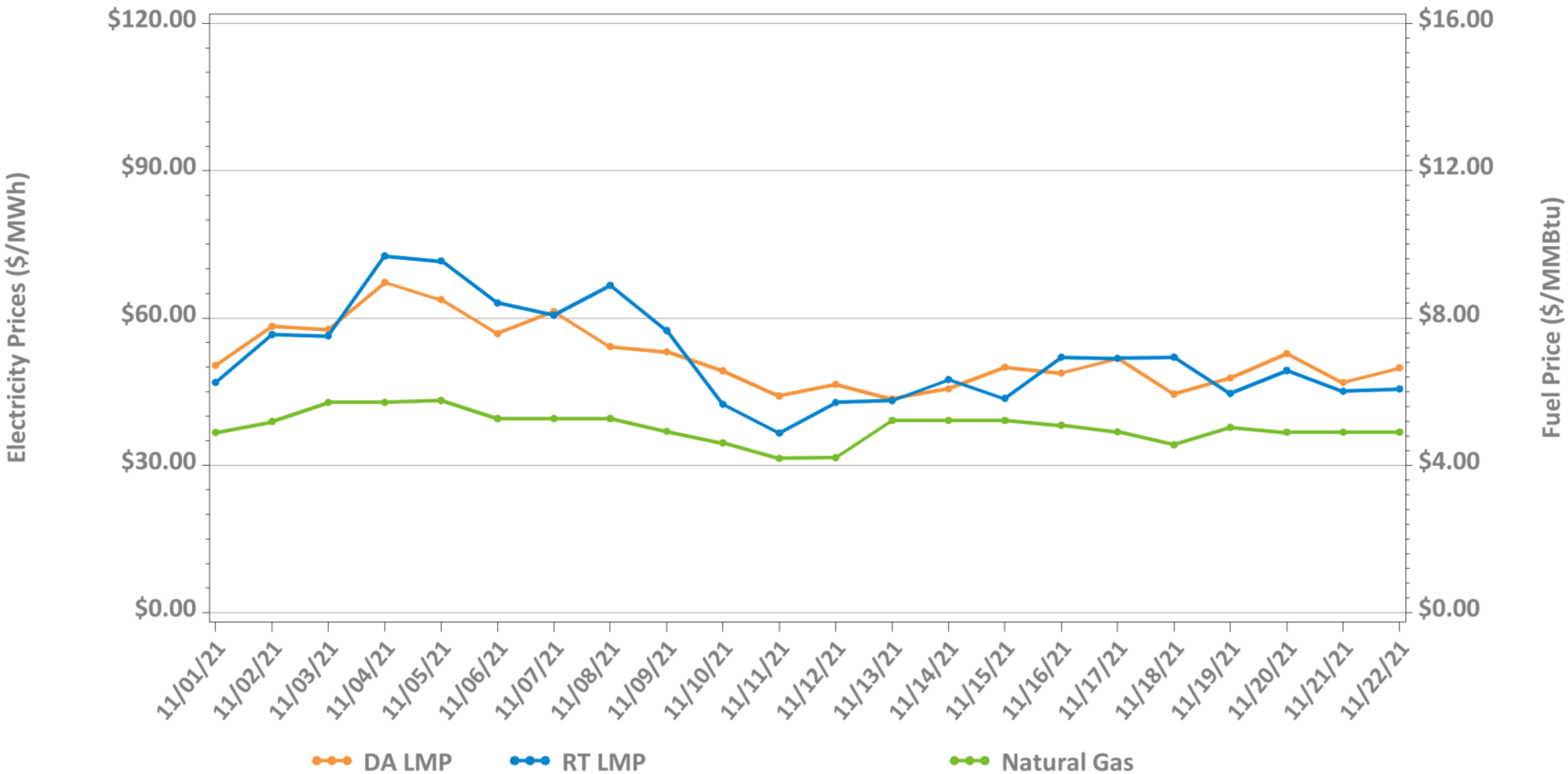
Dashboard Indicator




Ideally, MAE and Bias would be both equal to zero. Positive bias means less windpower was actually available compared to forecast. Negative bias means more windpower was actually available compared to forecast. Across all time frames, the ISO-NE/DNV 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: November 1-22, 2021

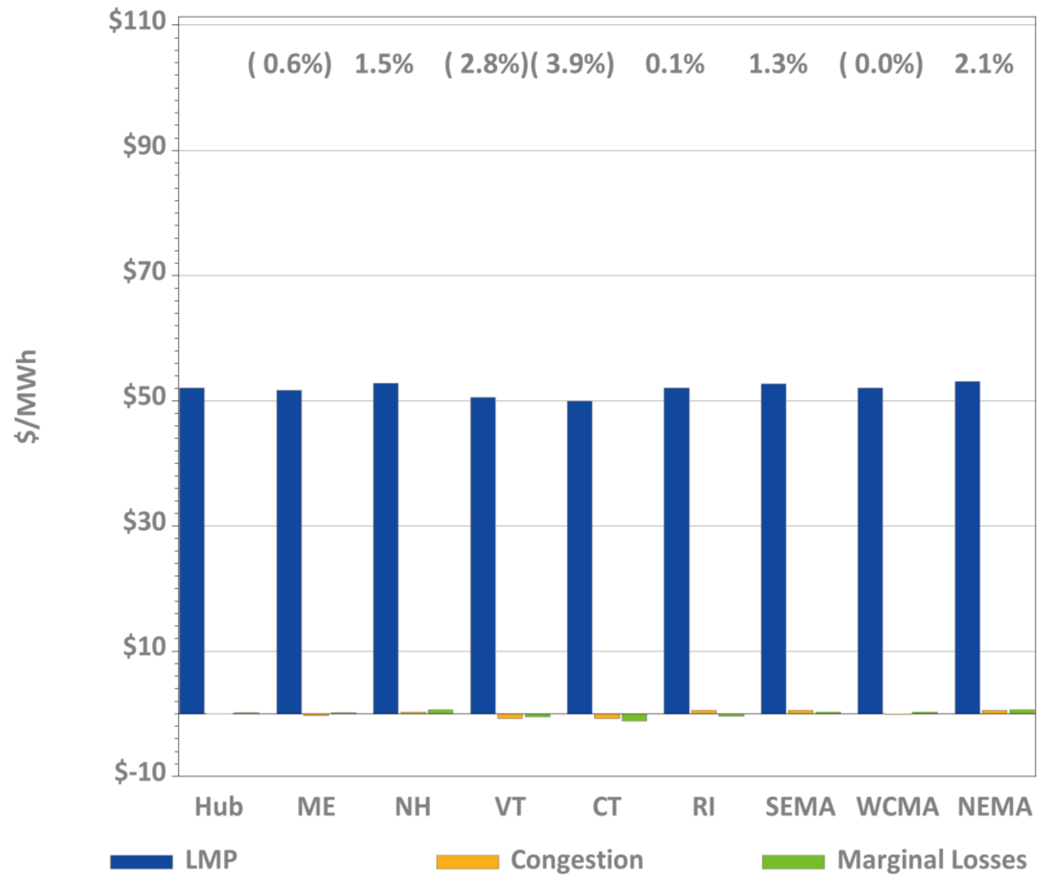



Underlying natural gas data furnished by:

ICE Global markets in clear view

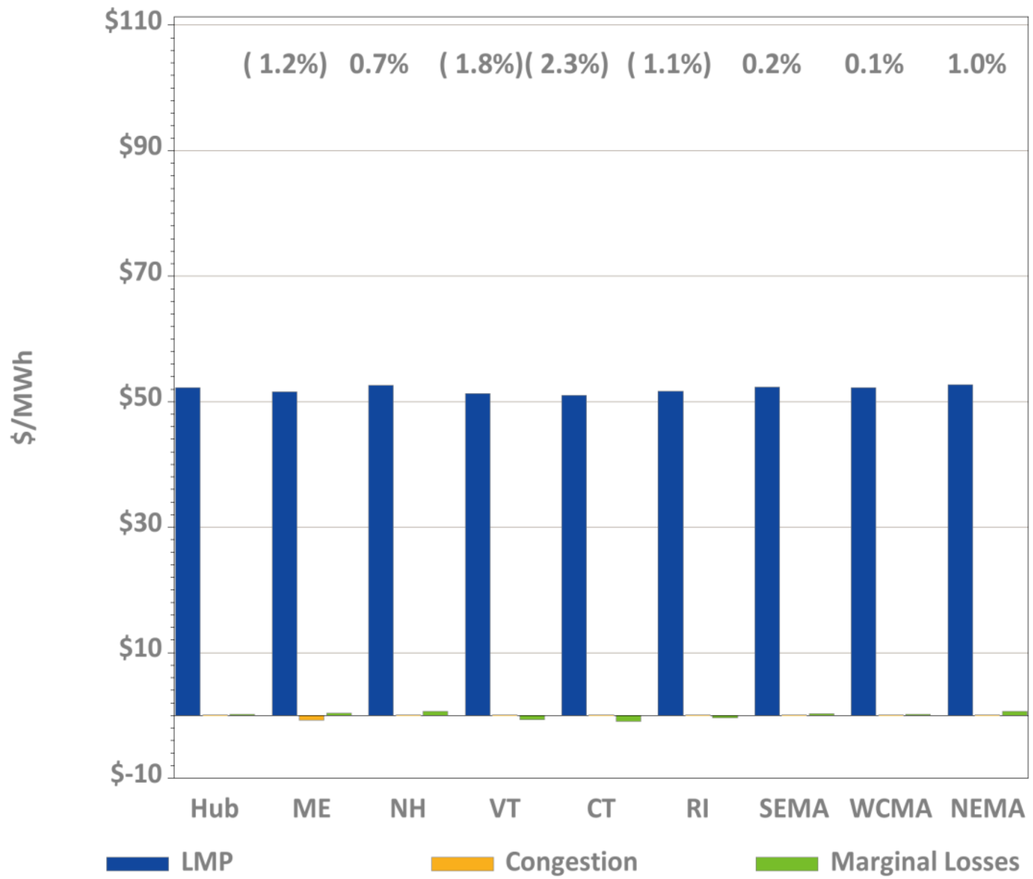
Average price difference over this period (DA-RT): $-0.19
Average price difference over this period ABS(DA-RT): $4.25
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 8%
Gas price is average of Massachusetts delivery points

# DA LMPs Average by Zone & Hub, November 2021




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

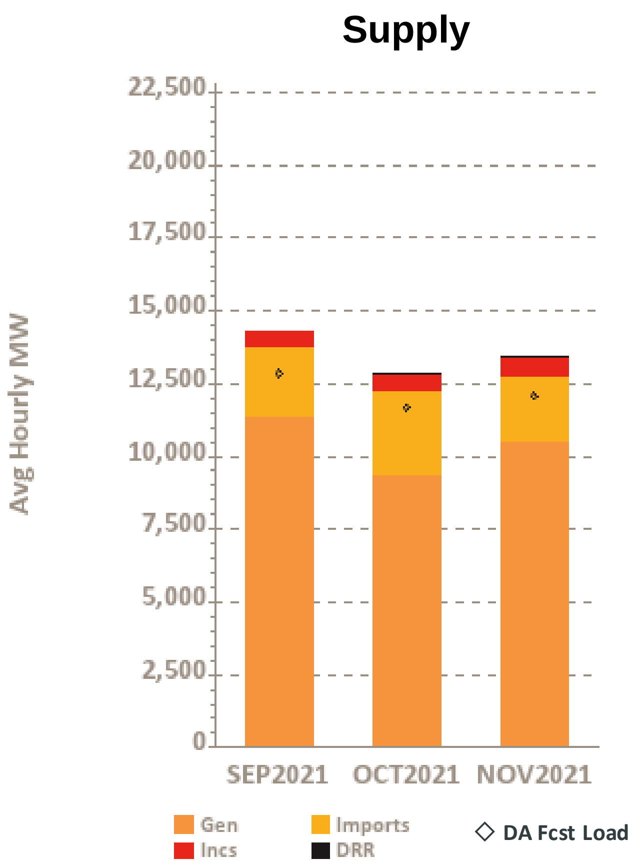
# RT LMPs Average by Zone & Hub, November 2021

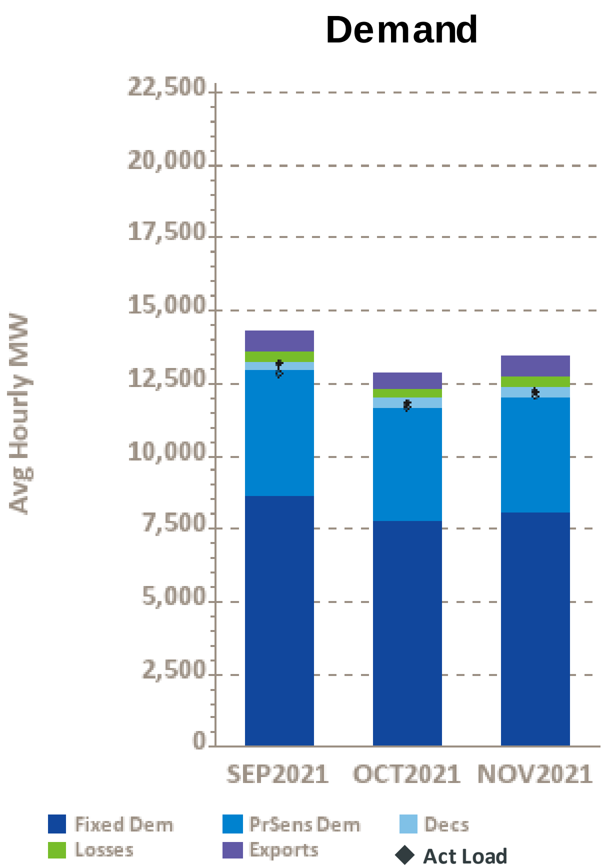


# Definitions

| 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

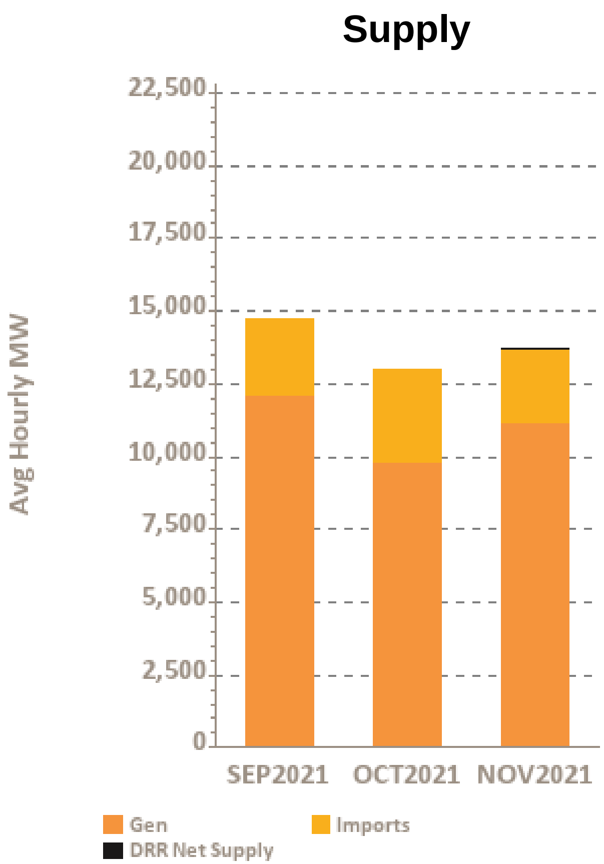


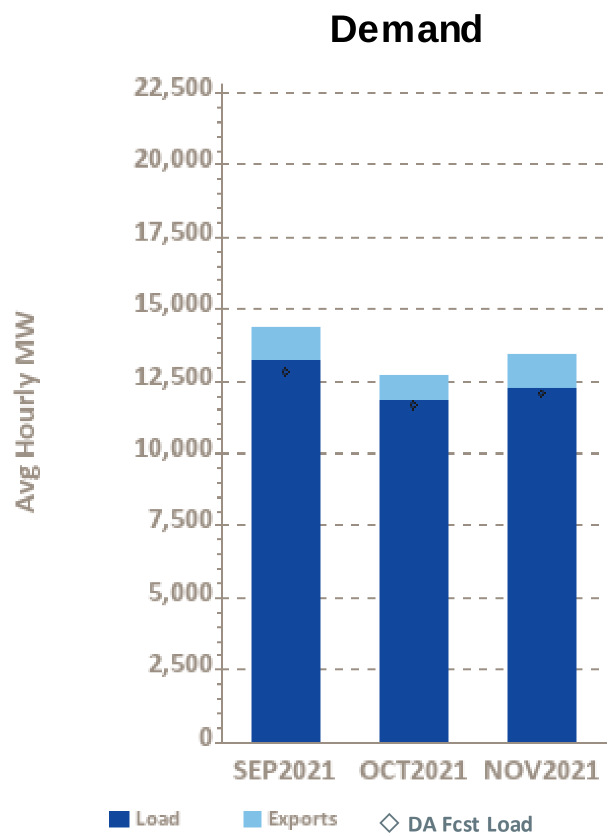




Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load
DRR – Demand Response Resource

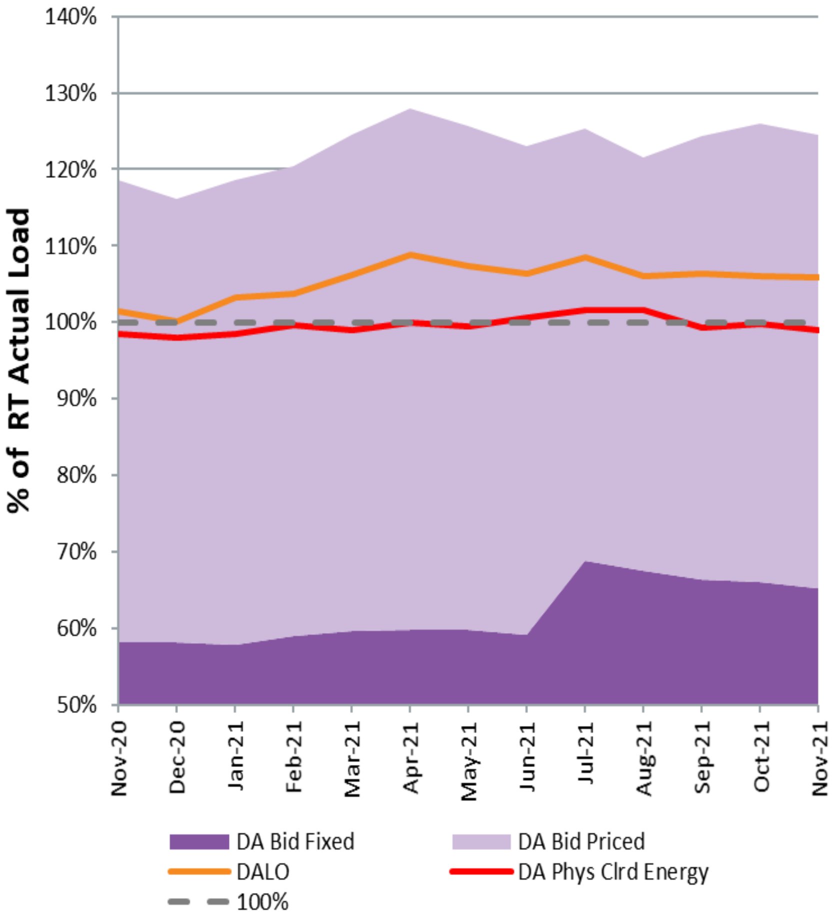
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

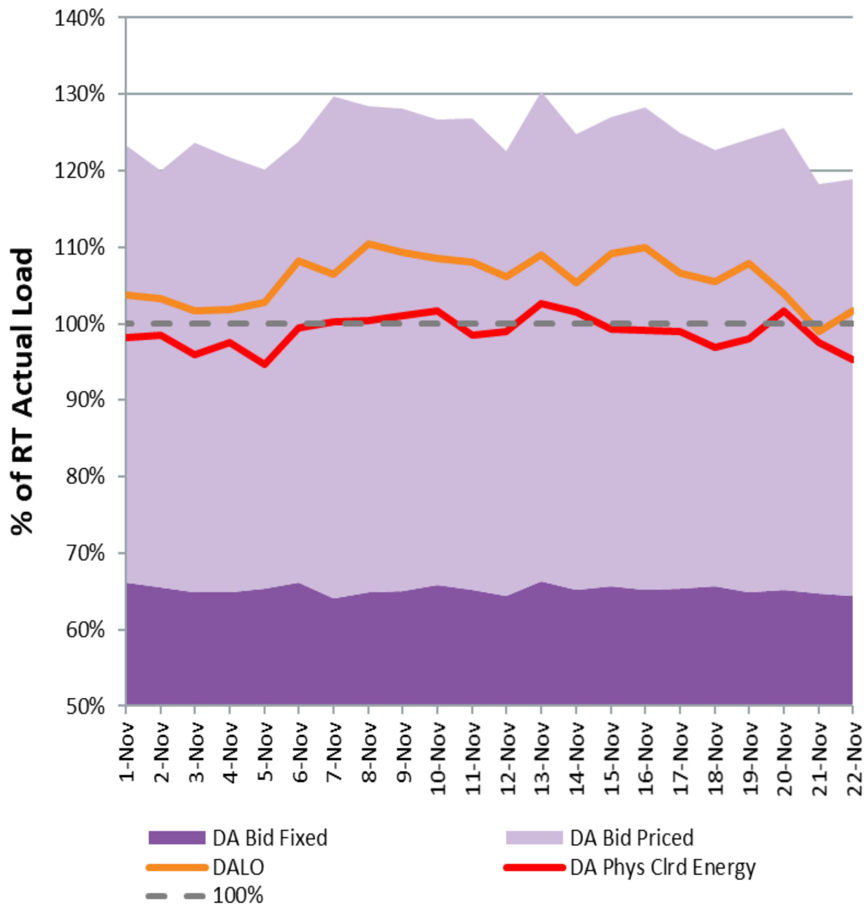
# Components of RT Supply and Demand – Last Three Months



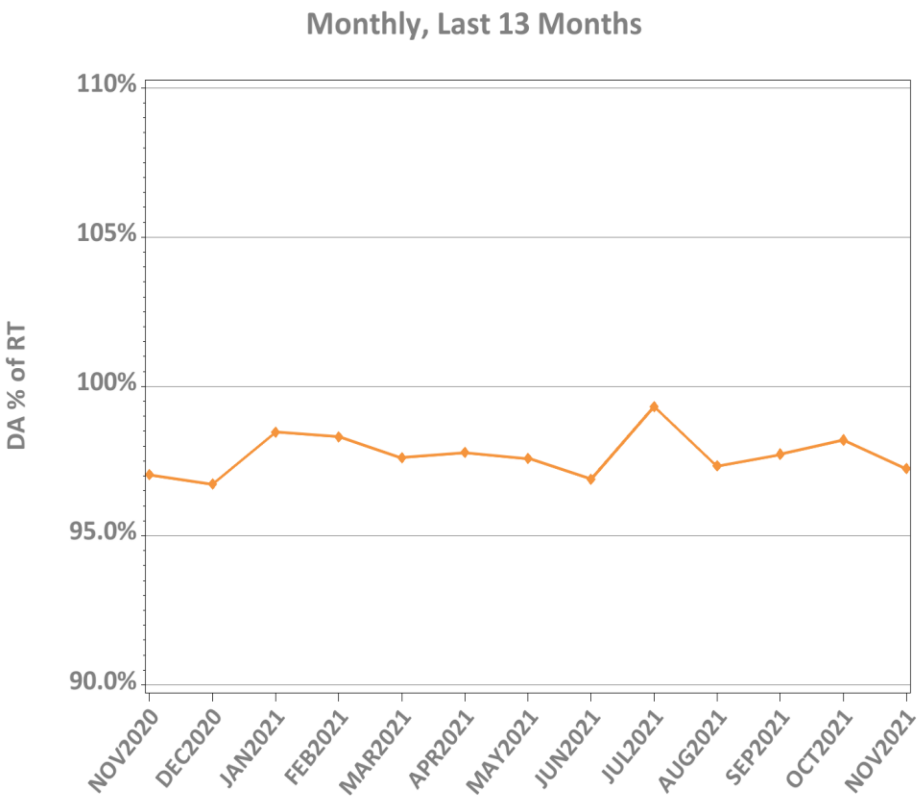
# DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

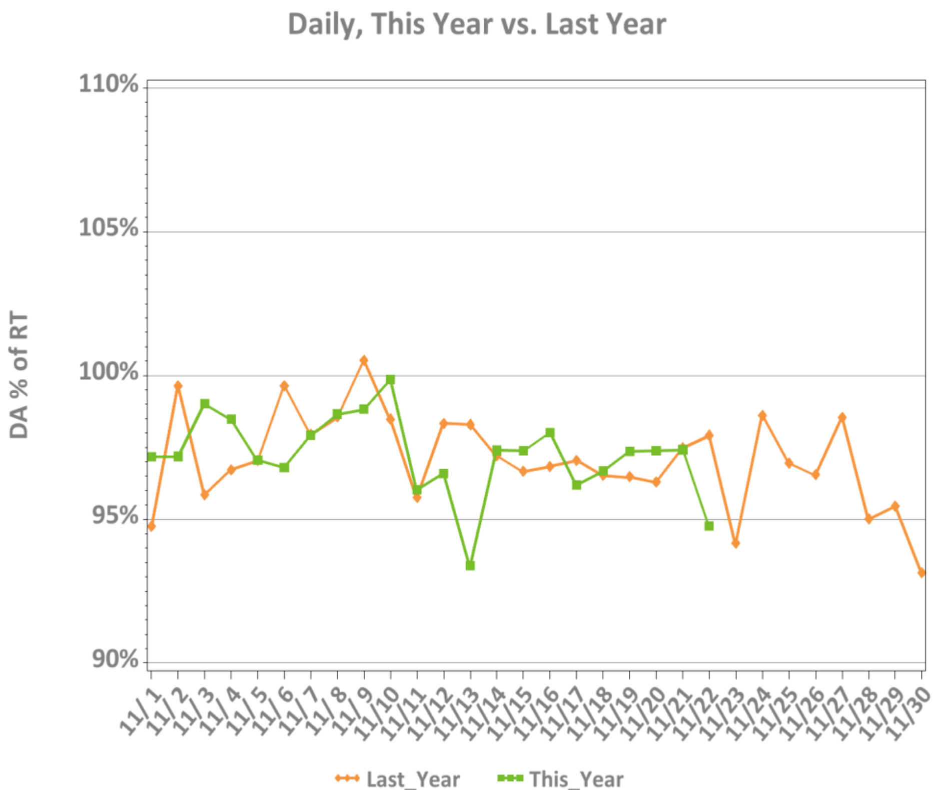



Note: Forecasted peak hour for each day is reflected in the above values. Shown for each day (chart on right) and then averaged for each month (chart on left). 'DA Bid' categories reflect load assets only (Virtual and export bids not reflected.)

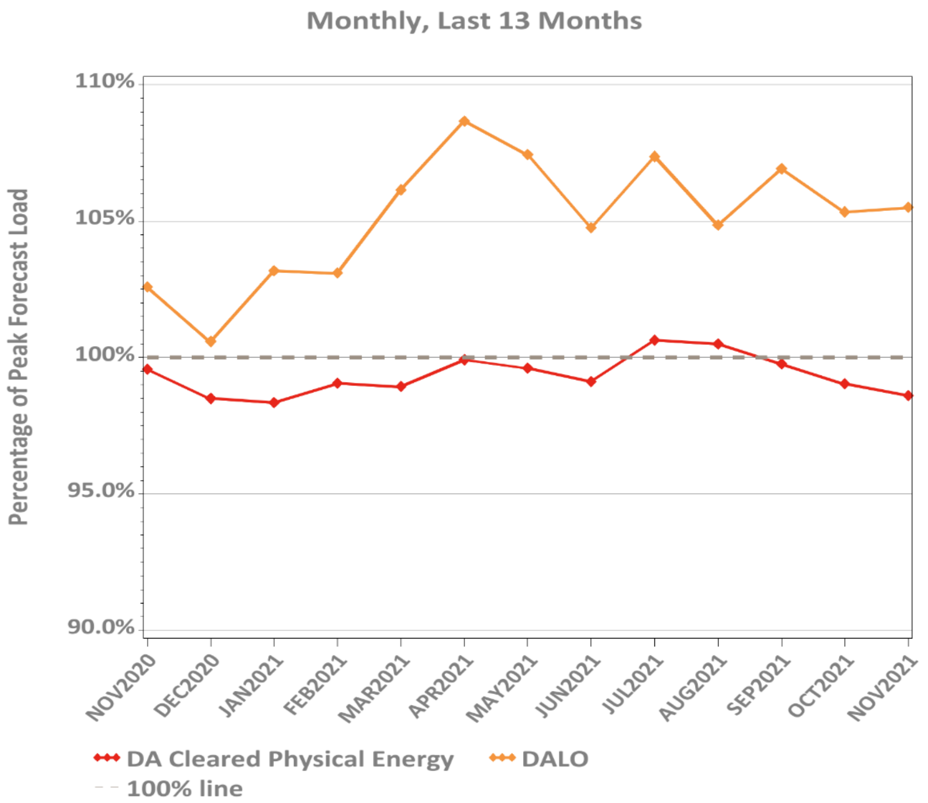
# DA vs. RT Load Obligation: November, This Year vs. Last Year

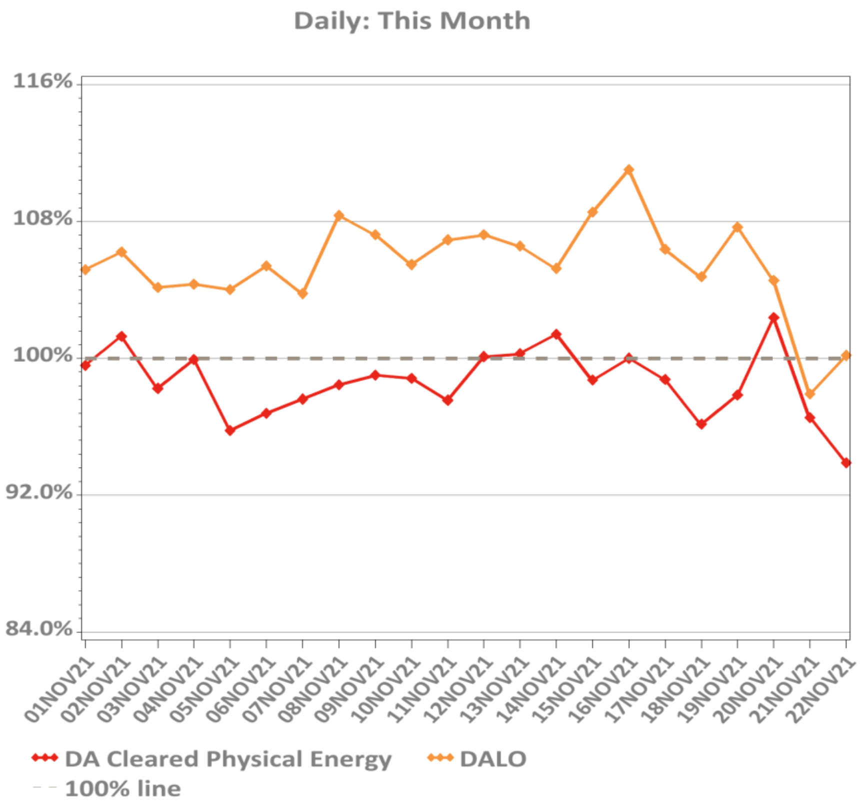



*Hourly average values

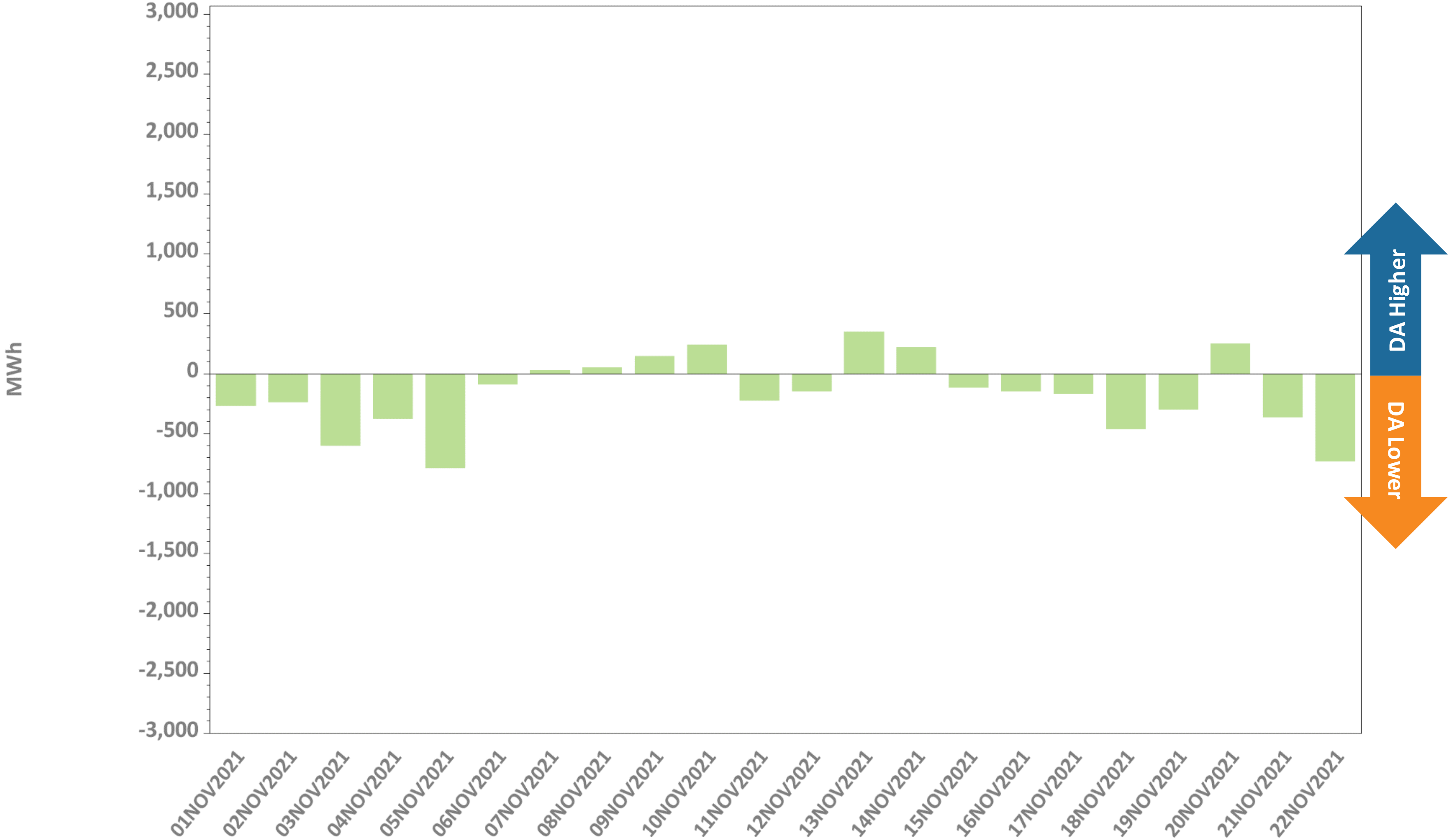
# DA Volumes as % of Forecast in Peak Hour



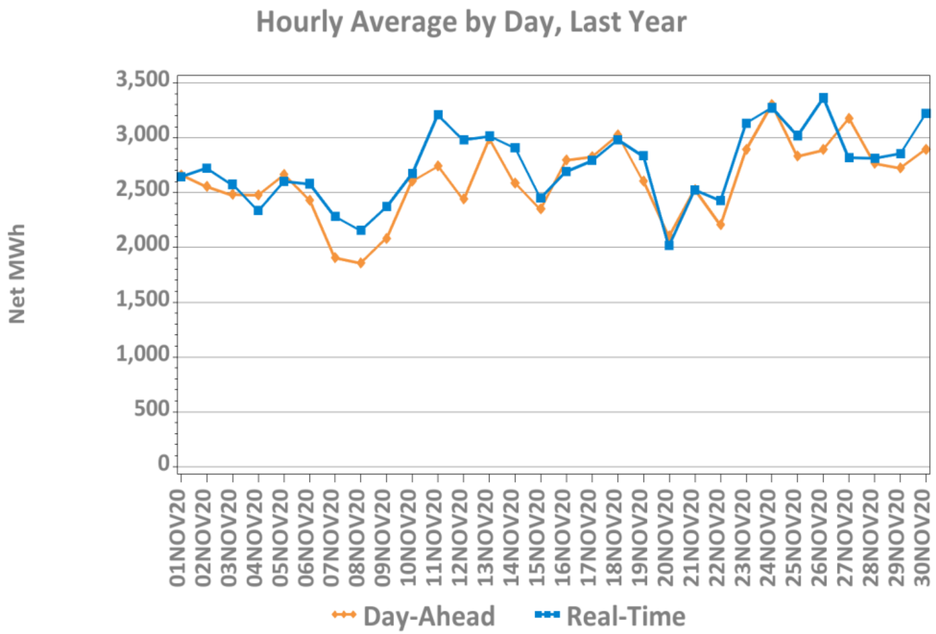

Note: There were no system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) during the month.

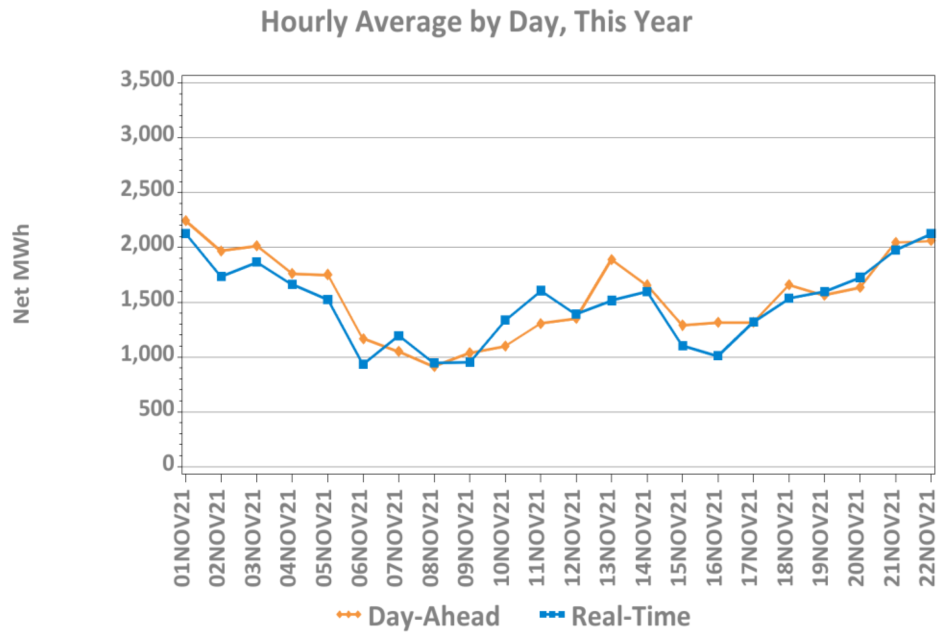
# DA Cleared Physical Energy Difference from RT System Load at Forecasted Peak Hour*




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

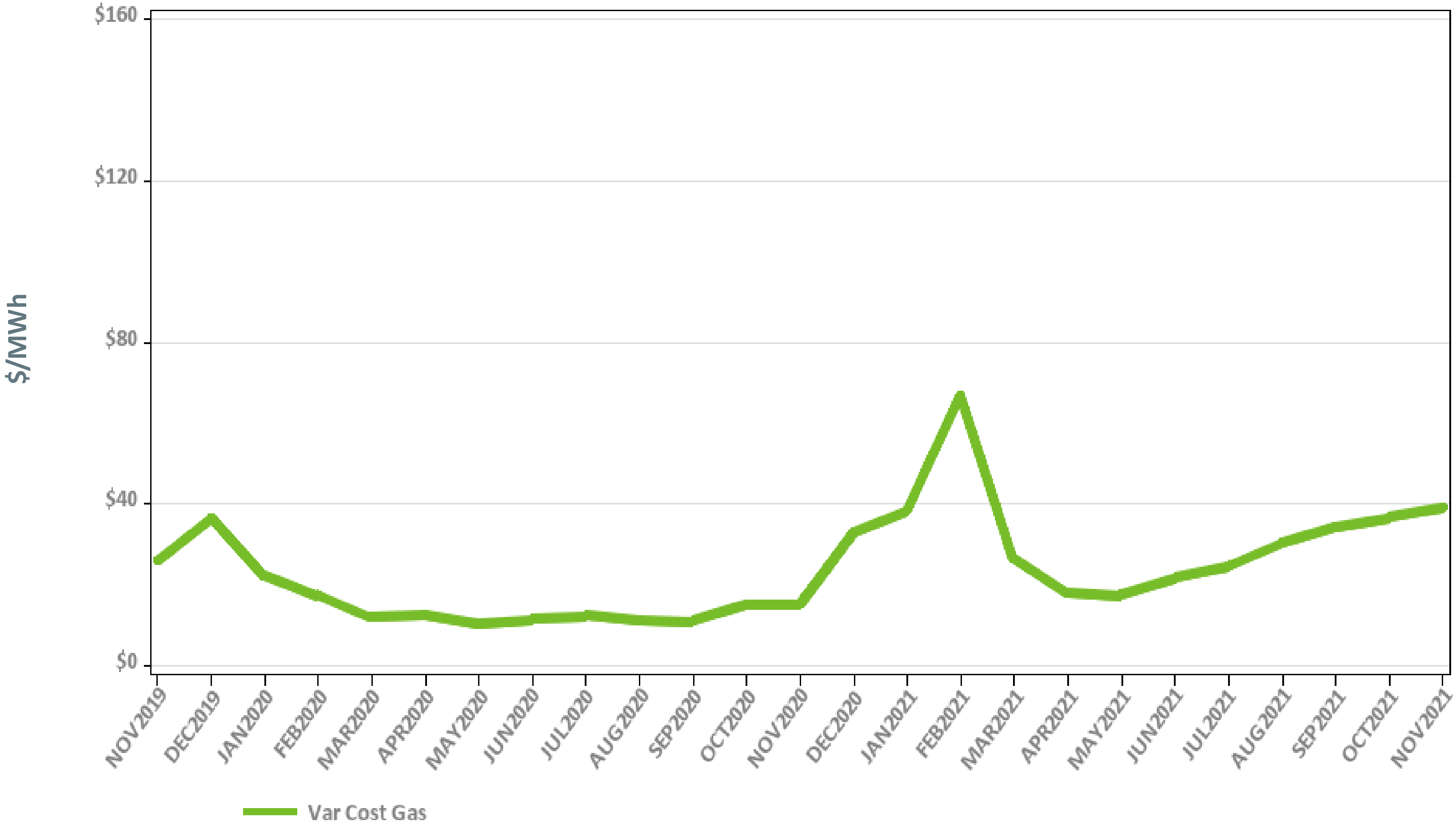
# DA vs. RT Net Interchange November 2020 vs. November 2021




**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

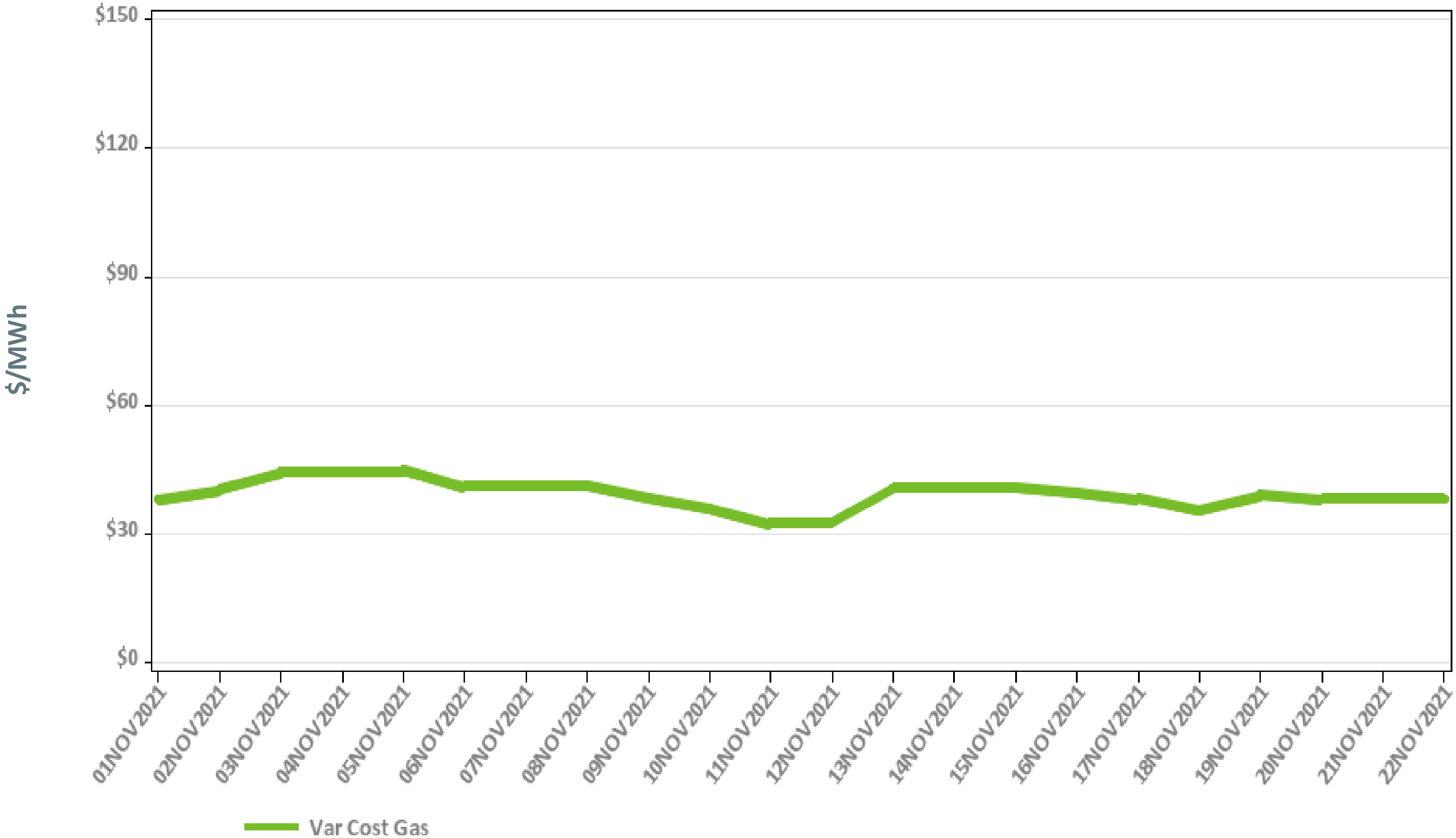



Underlying natural gas data furnished by:

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

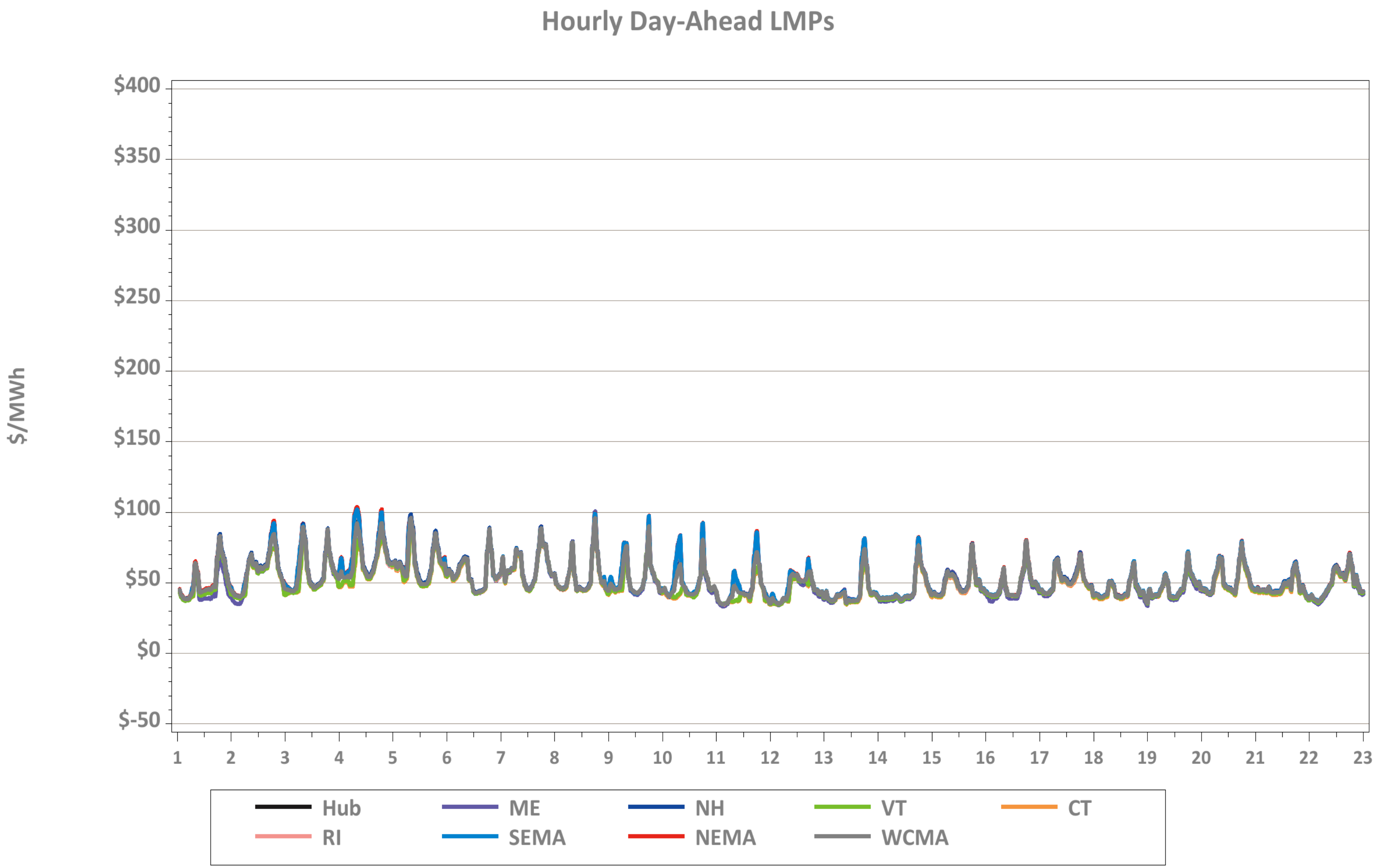



Underlying natural gas data furnished by:

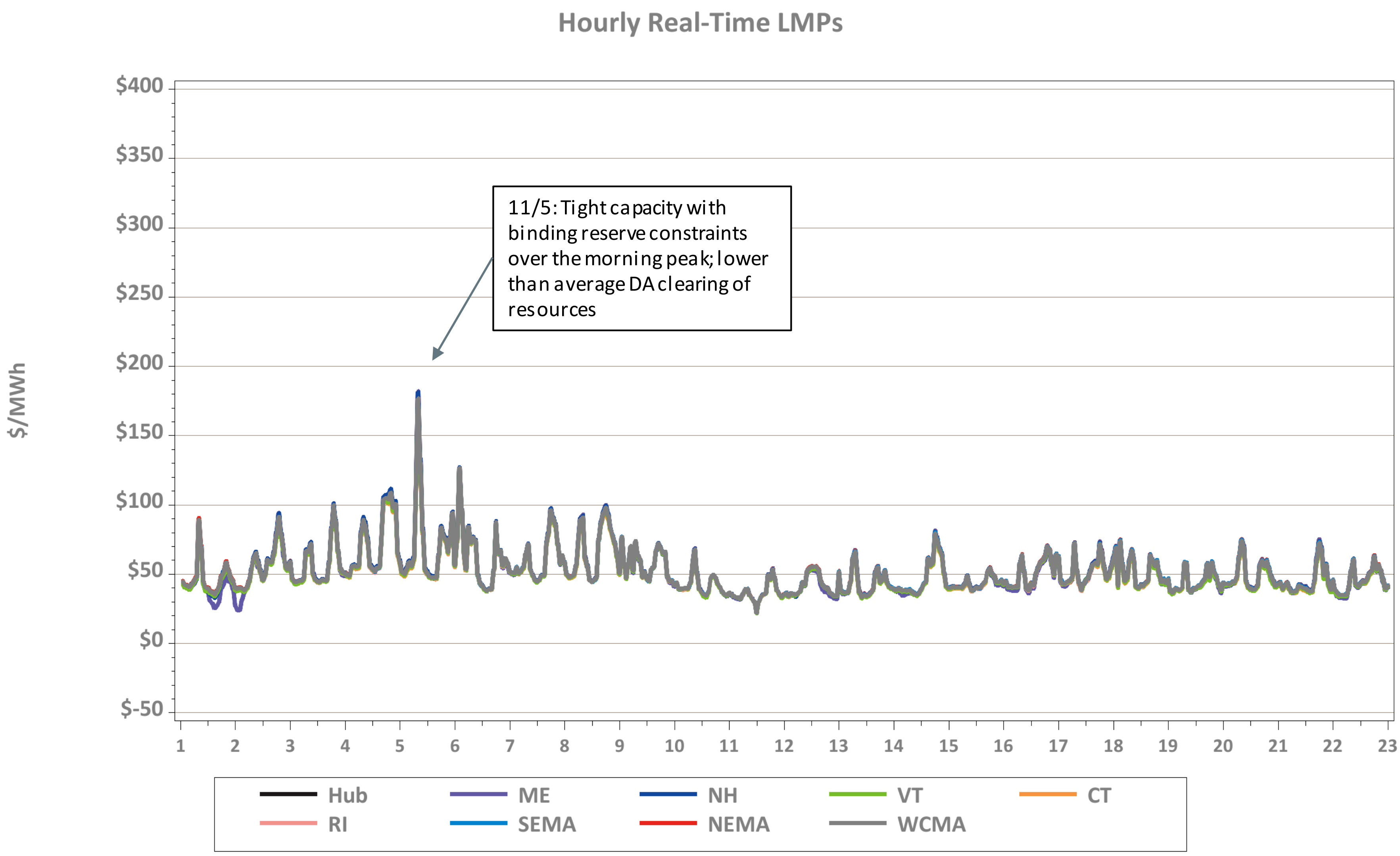
ICE Global markets in clear view

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

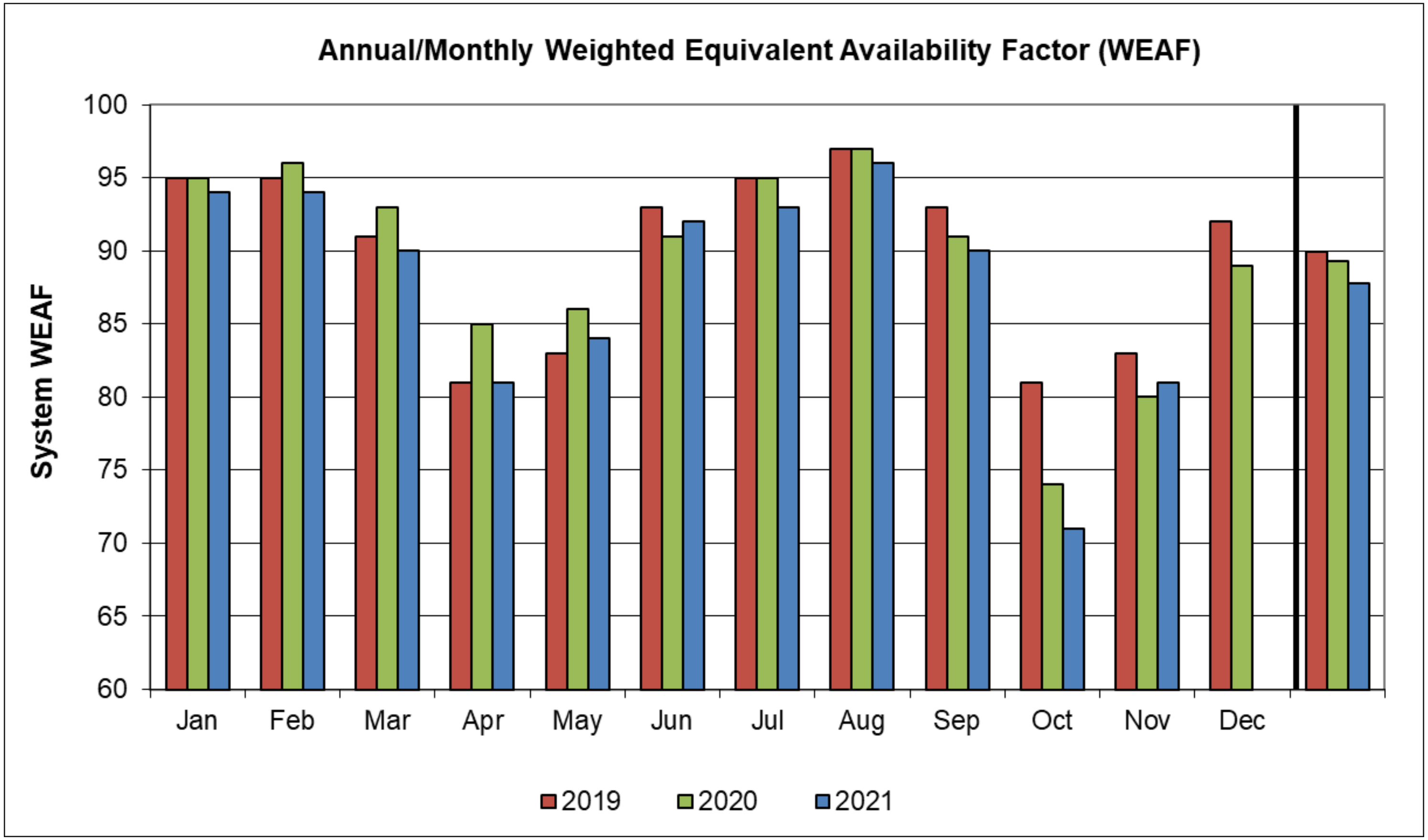
# Hourly DA LMPs, November 1-22, 2021



# Hourly RT LMPs, November 1-22, 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 | 71 | 81 | | 88 |
| **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 11/17/2021

# BACK-UP DETAIL

# DEMAND RESPONSE

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

| Load Zone | ADCR* | On Peak | Seasonal Peak | Total |
|---|---|---|---|---|
| ME | 96.7 | 157.5 | 0.0 | 254.1 |
| NH | 39.2 | 148.9 | 0.0 | 188.1 |
| VT | 46.3 | 161.9 | 0.0 | 208.2 |
| CT | 121.5 | 113.6 | 630.9 | 866.0 |
| RI | 32.7 | 319.8 | 0.0 | 352.4 |
| SEMA | 42.7 | 500.3 | 0.0 | 543.1 |
| WCMA | 74.8 | 524.9 | 18.0 | 617.7 |
| NEMA | 57.6 | 847.2 | 0.0 | 904.8 |
| **Total** | **511.5** | **2,774.1** | **648.9** | **3,934.4** |

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

# NEW GENERATION

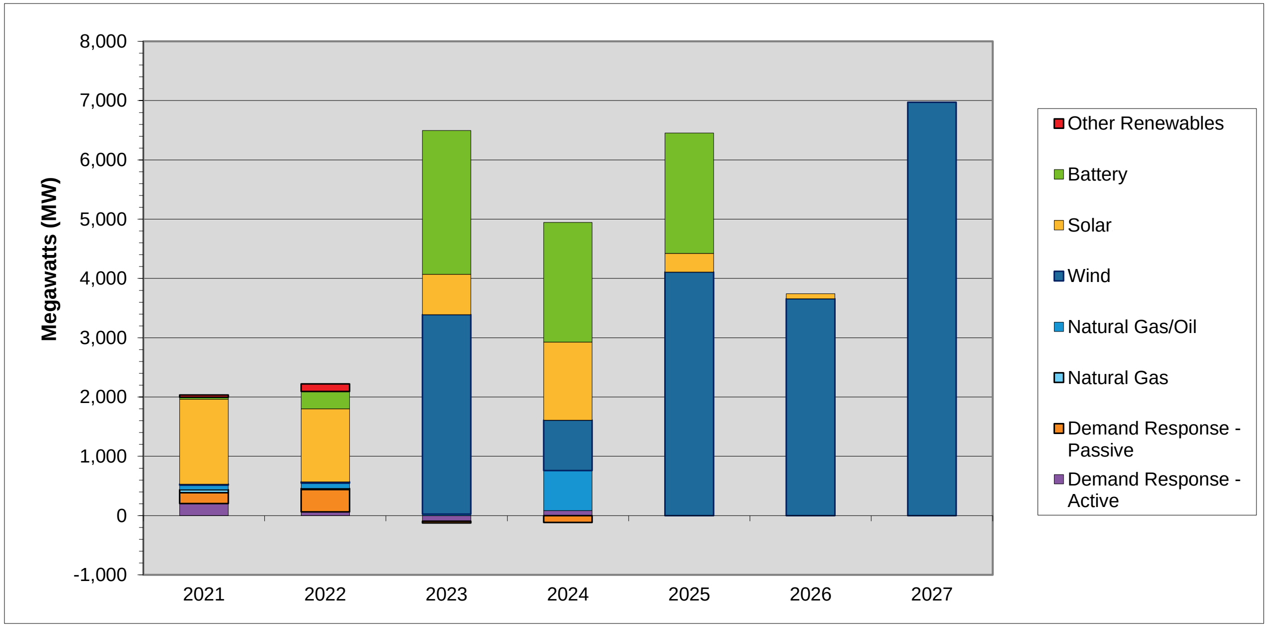
# New Generation Update

## *Based on Queue as of 11/26/21*

- Two projects totaling 213 MW were added to the interconnection queue since the last update
  - They consist of one battery project and one solar project, with in-service dates of 2024
- Four projects were withdrawn
- In total, 300 generation projects are currently being tracked by the ISO, totaling approximately 31,947 MW

# Actual and Projected Annual Capacity Additions

## *By Supply Fuel Type and Demand Resource Type*



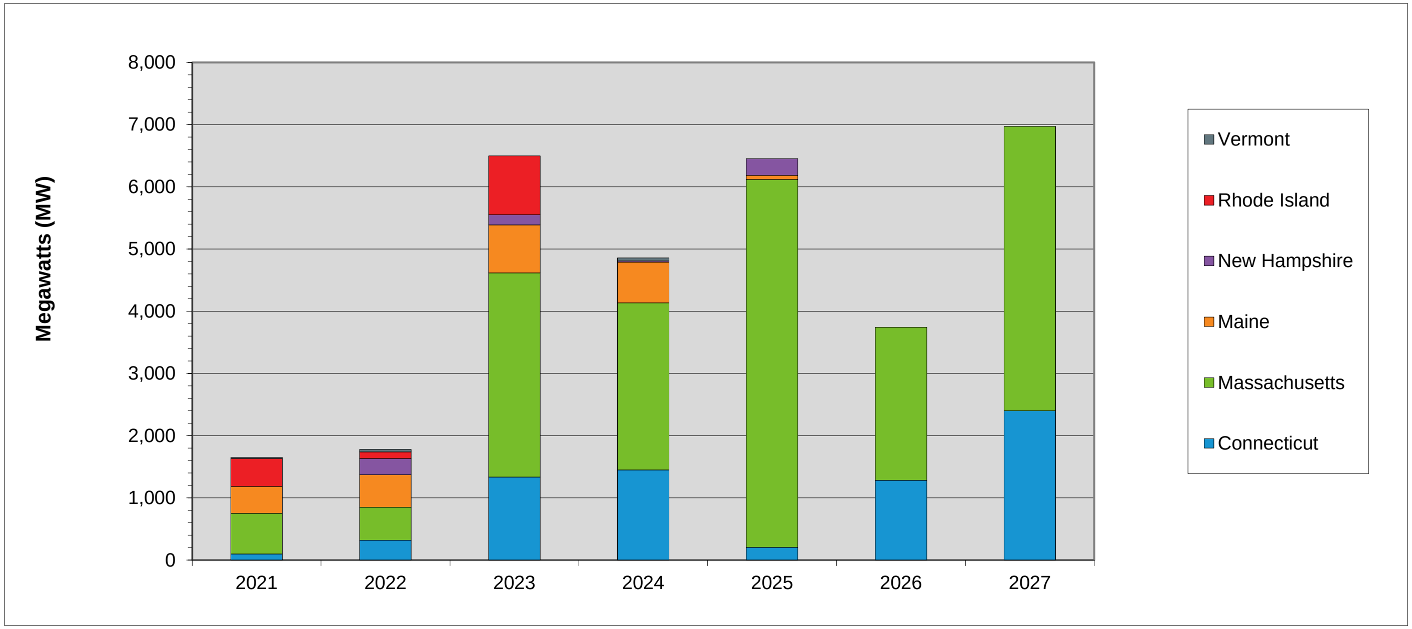

| | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | Total MW | % of Total[1] |
|---|---|---|---|---|---|---|---|---|---|
| Other Renewables | 38 | 128 | 0 | 0 | 0 | 0 | 0 | 166 | 0.5 |
| Battery | 34 | 293 | 2,427 | 2,015 | 2,030 | 0 | 0 | 6,799 | 20.8 |
| Solar[2] | 1,431 | 1,232 | 679 | 1,319 | 316 | 83 | 0 | 5,060 | 15.5 |
| Wind | 19 | 20 | 3,367 | 852 | 4,107 | 3,658 | 6,972 | 18,995 | 58.2 |
| Natural Gas/Oil[3] | 76 | 89 | 23 | 672 | 0 | 0 | 0 | 860 | 2.6 |
| Natural Gas | 49 | 18 | 0 | 0 | 0 | 0 | 0 | 67 | 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** | **2,035** | **2,222** | **6,374** | **4,830** | **6,453** | **3,741** | **6,972** | **32,627** | **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 | 106 | 944 | 0 | 0 | 0 | 0 | 1,500 | 4.7 |
| **New Hampshire** | 0 | 261 | 164 | 20 | 272 | 0 | 0 | 717 | 2.2 |
| **Maine** | 433 | 525 | 774 | 654 | 64 | 0 | 0 | 2,450 | 7.7 |
| **Massachusetts** | 650 | 531 | 3,278 | 2,687 | 5,912 | 2,458 | 4,572 | 20,088 | 62.9 |
| **Connecticut** | 99 | 317 | 1,336 | 1,447 | 205 | 1,283 | 2,400 | 7,087 | 22.2 |
| **Totals** | **1,647** | **1,780** | **6,496** | **4,858** | **6,453** | **3,741** | **6,972** | **31,947** | **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 | 41 | 6,799 | 0 | 0 | 41 | 6,799 |
| Fuel Cell | 2 | 30 | 0 | 0 | 2 | 30 |
| Hydro | 3 | 99 | 2 | 71 | 1 | 28 |
| Natural Gas | 7 | 67 | 0 | 0 | 7 | 67 |
| Natural Gas/Oil | 7 | 860 | 1 | 14 | 6 | 846 |
| Nuclear | 1 | 37 | 0 | 0 | 1 | 37 |
| Solar | 209 | 5,060 | 18 | 238 | 191 | 4,822 |
| Wind | 30 | 18,995 | 1 | 15 | 29 | 18,980 |
| Total | 300 | 31,947 | 22 | 338 | 278 | 31,609 |

- 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 | 107 | 1 | 5 | 5 | 102 |
| Intermediate | 8 | 818 | 1 | 14 | 7 | 804 |
| Peaker | 256 | 12,027 | 19 | 304 | 237 | 11,723 |
| Wind Turbine | 30 | 18,995 | 1 | 15 | 29 | 18,980 |
| Total | 300 | 31,947 | 22 | 338 | 278 | 31,609 |

- 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*

| Unit Type | Total | | Baseload | | Intermediate | | Peaker | | Wind Turbine | |
|---|---|---|---|---|---|---|---|---|---|---|
| | No. of Projects | Capacity (MW) | No. of Projects | Capacity (MW) | No. of Projects | Capacity (MW) | No. of Projects | Capacity (MW) | No. of Projects | Capacity (MW) |
| Biomass/Wood Waste | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Battery Storage | 41 | 6,799 | 0 | 0 | 0 | 0 | 41 | 6,799 | 0 | 0 |
| Fuel Cell | 2 | 30 | 2 | 30 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydro | 3 | 99 | 2 | 33 | 0 | 0 | 1 | 66 | 0 | 0 |
| Natural Gas | 7 | 67 | 1 | 7 | 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 | 209 | 5,060 | 0 | 0 | 0 | 0 | 209 | 5,060 | 0 | 0 |
| Wind | 30 | 18,995 | 0 | 0 | 0 | 0 | 0 | 0 | 30 | 18,995 |
| Total | 300 | 31,947 | 6 | 107 | 8 | 818 | 256 | 12,027 | 30 | 18,995 |

- 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 | | | | |
| | *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 | | | | |
| | *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 | | | | | | |
| | *Passive Demand* | 3,212.865 | | | | | | |
| **Demand Total** | | **3,890.538** | | | | | | |
| Generator | *Non-Intermittent* | 28,154.203 | | | | | | |
| | *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

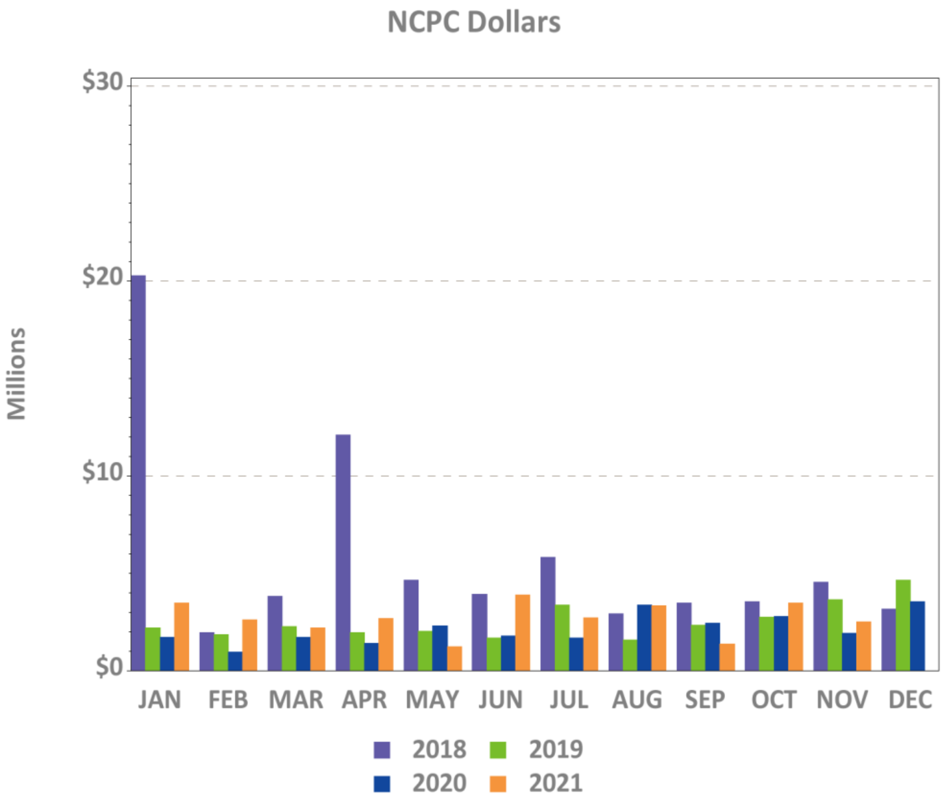
# Definitions

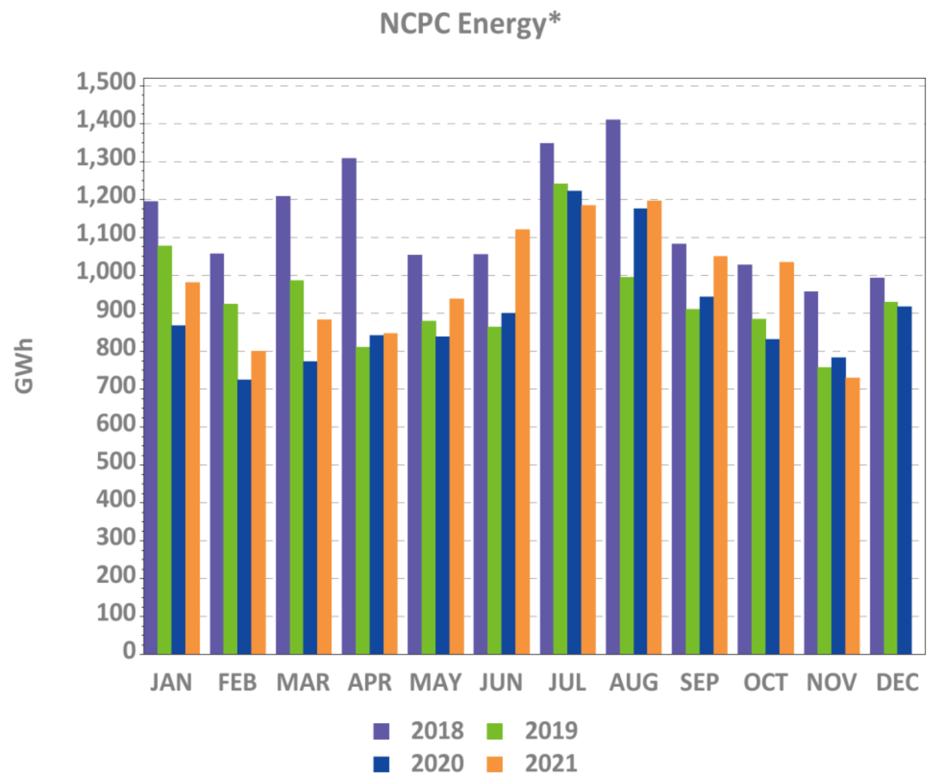
| | |
|---|---|
| 1st Contingency NCPC Payments | Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally |
| 2nd Contingency NCPC Payments | Reliability costs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

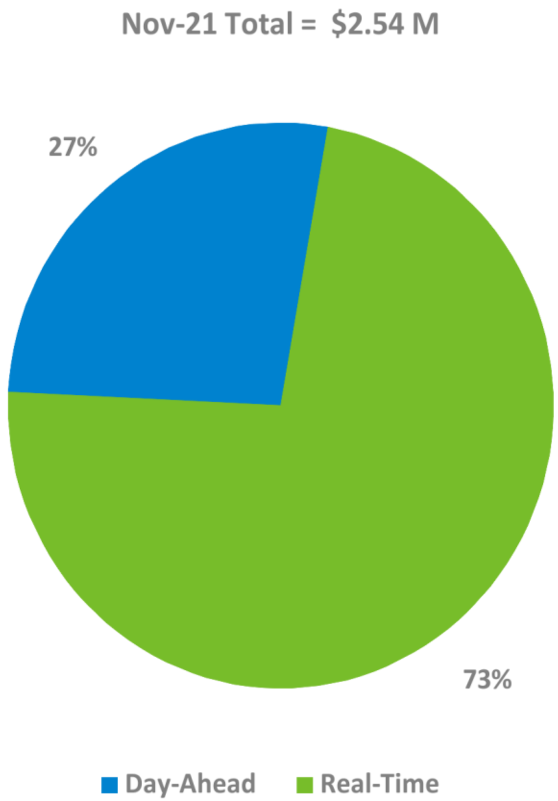
# Year-Over-Year Total NCPC Dollars and Energy

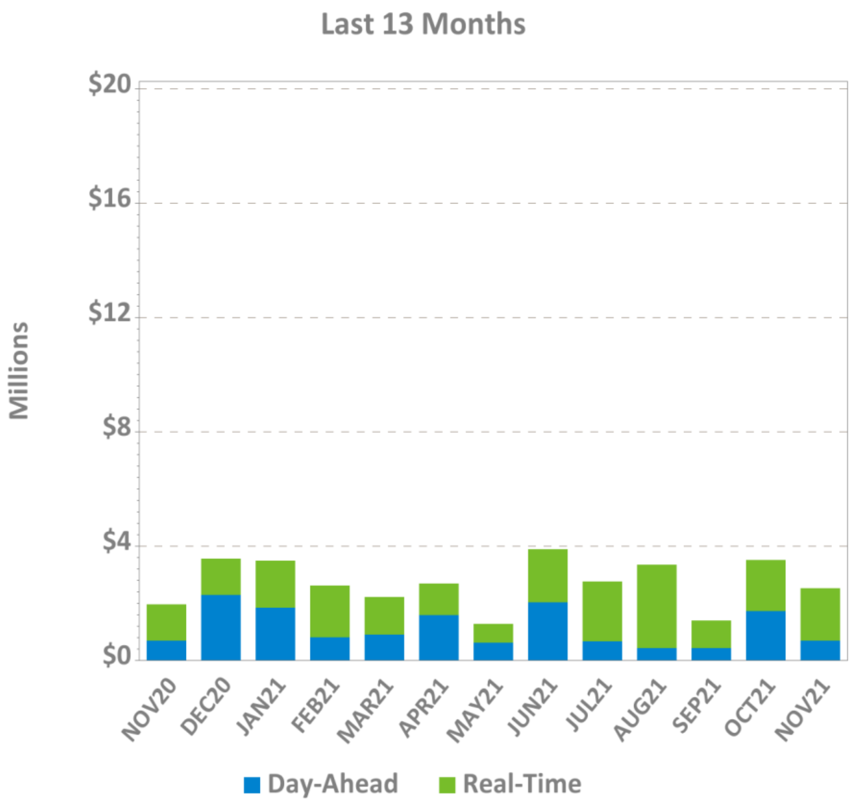


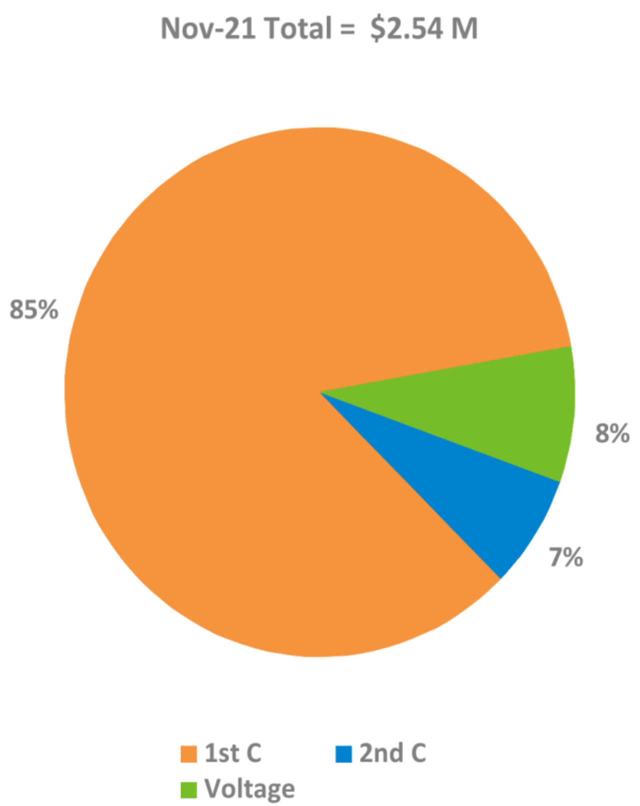

* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

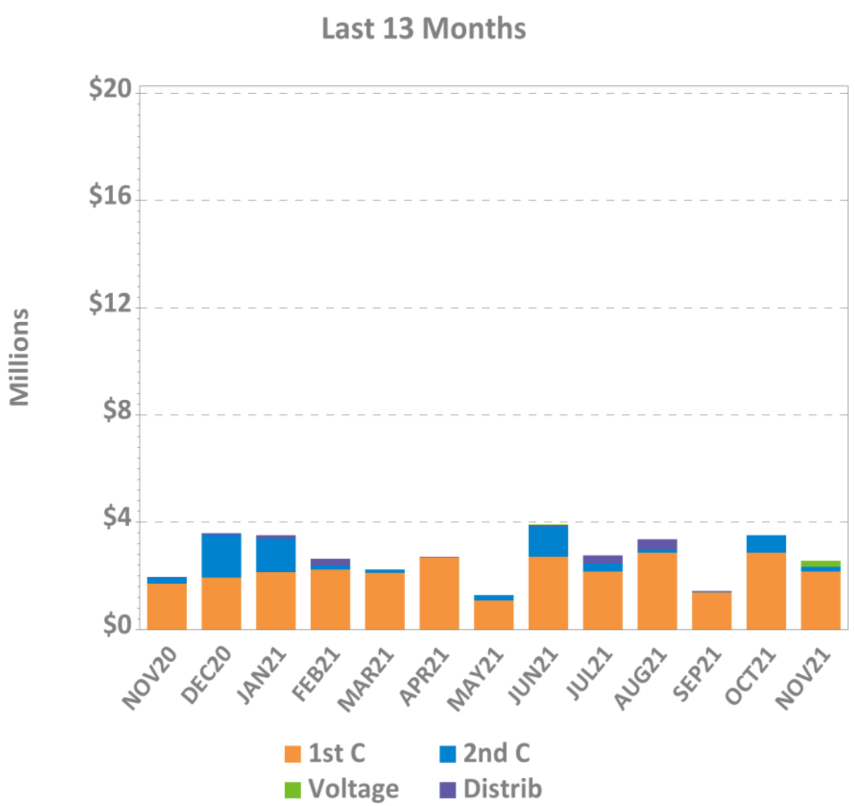
# DA and RT NCPC Charges



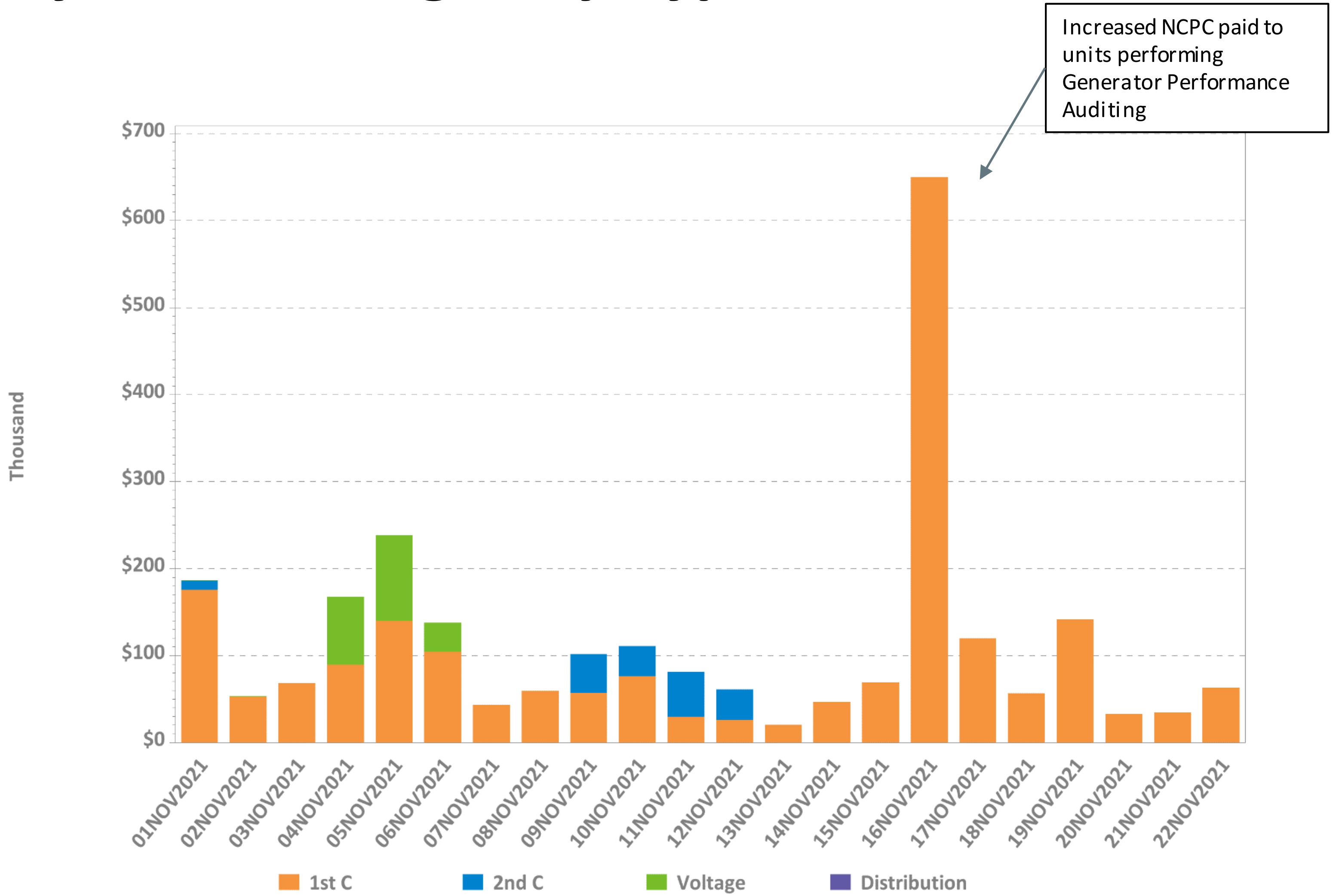
# NCPC Charges by Type



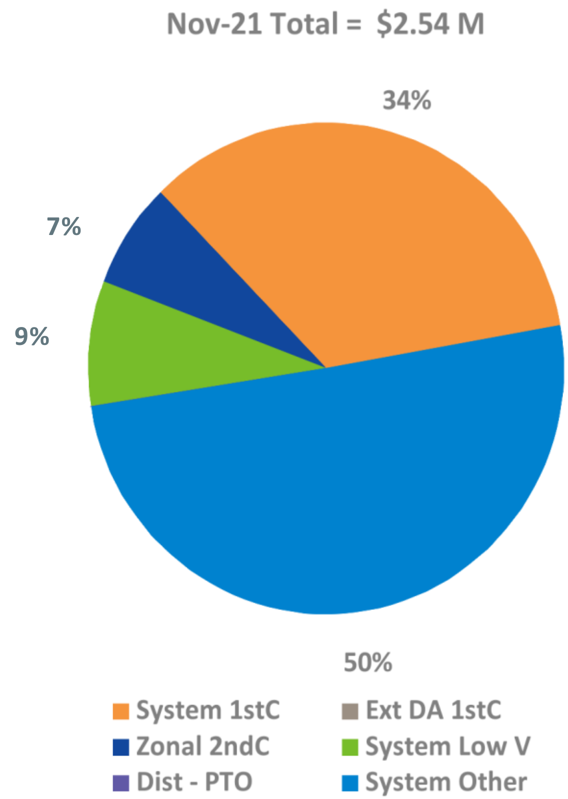



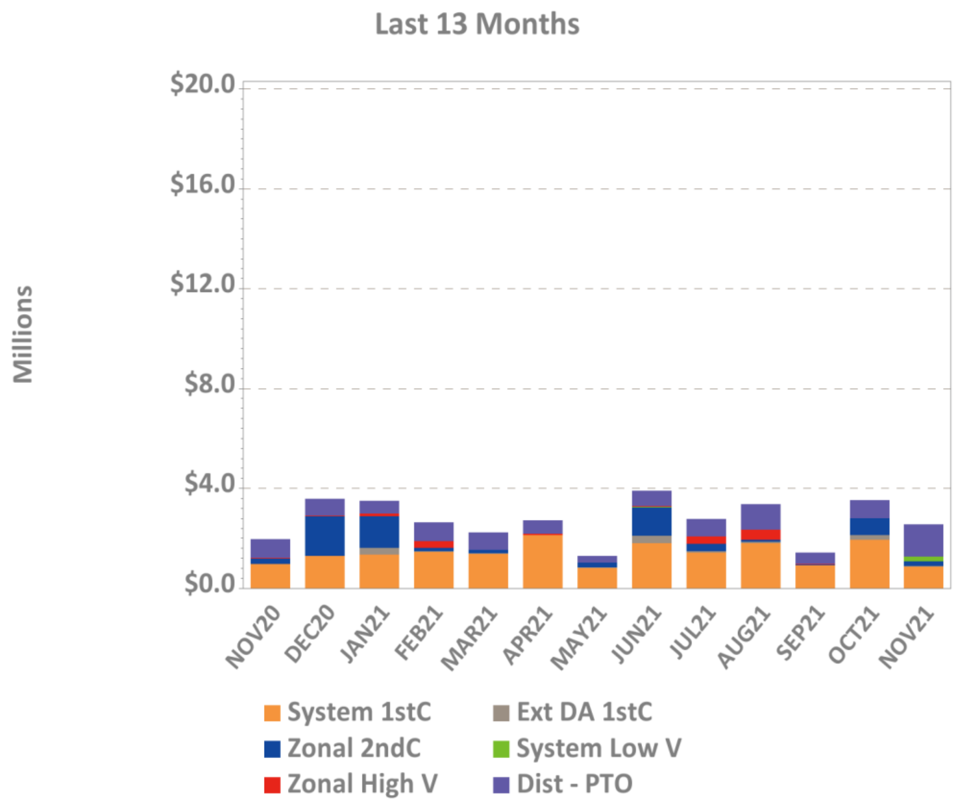

**1st C – First Contingency**
**2nd C – Second Contingency**
**Distrib – Distribution**
**Voltage – Voltage**

# Daily NCPC Charges by Type



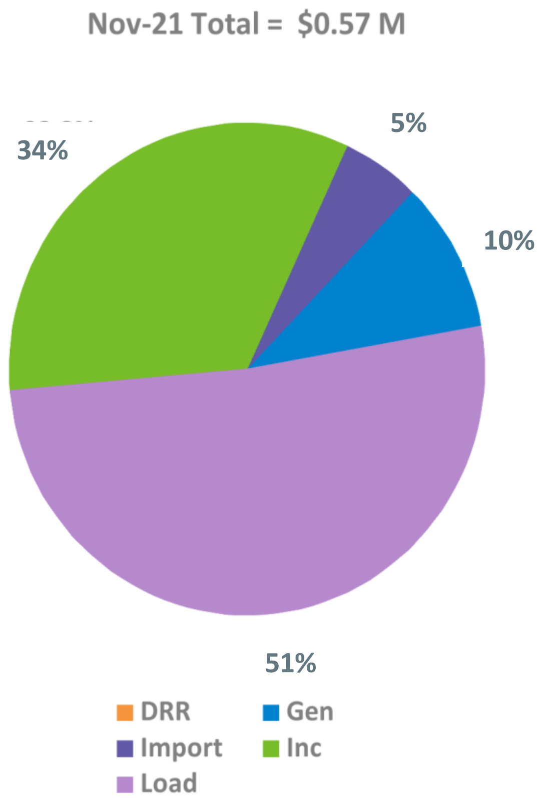
# NCPC Charges by Allocation

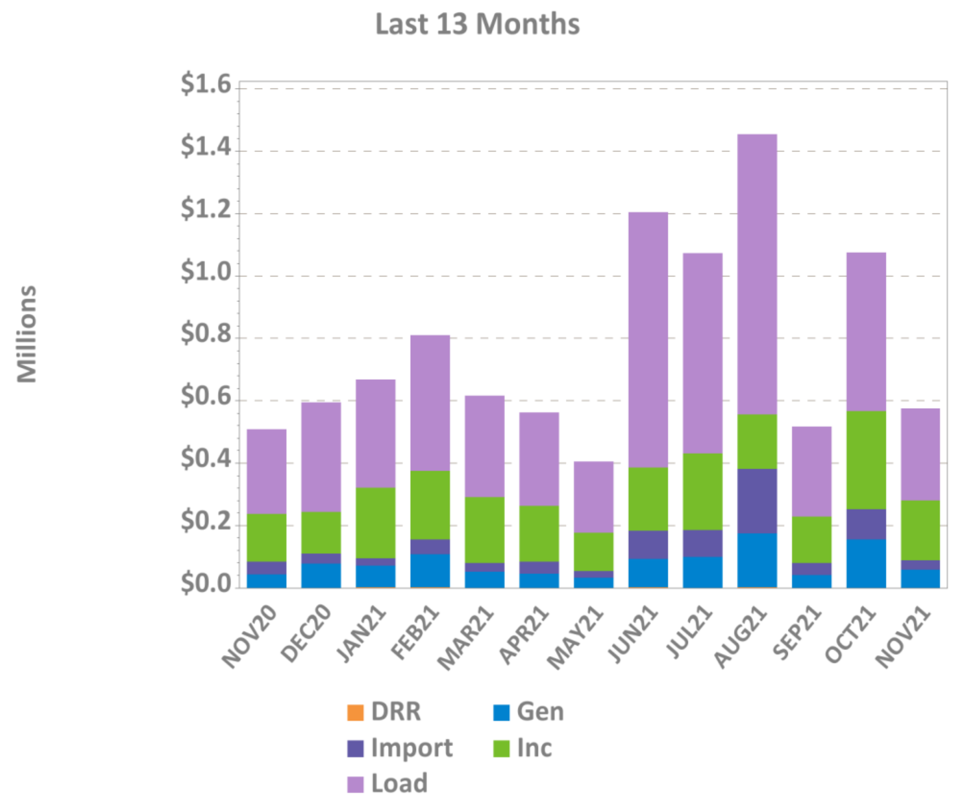



Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

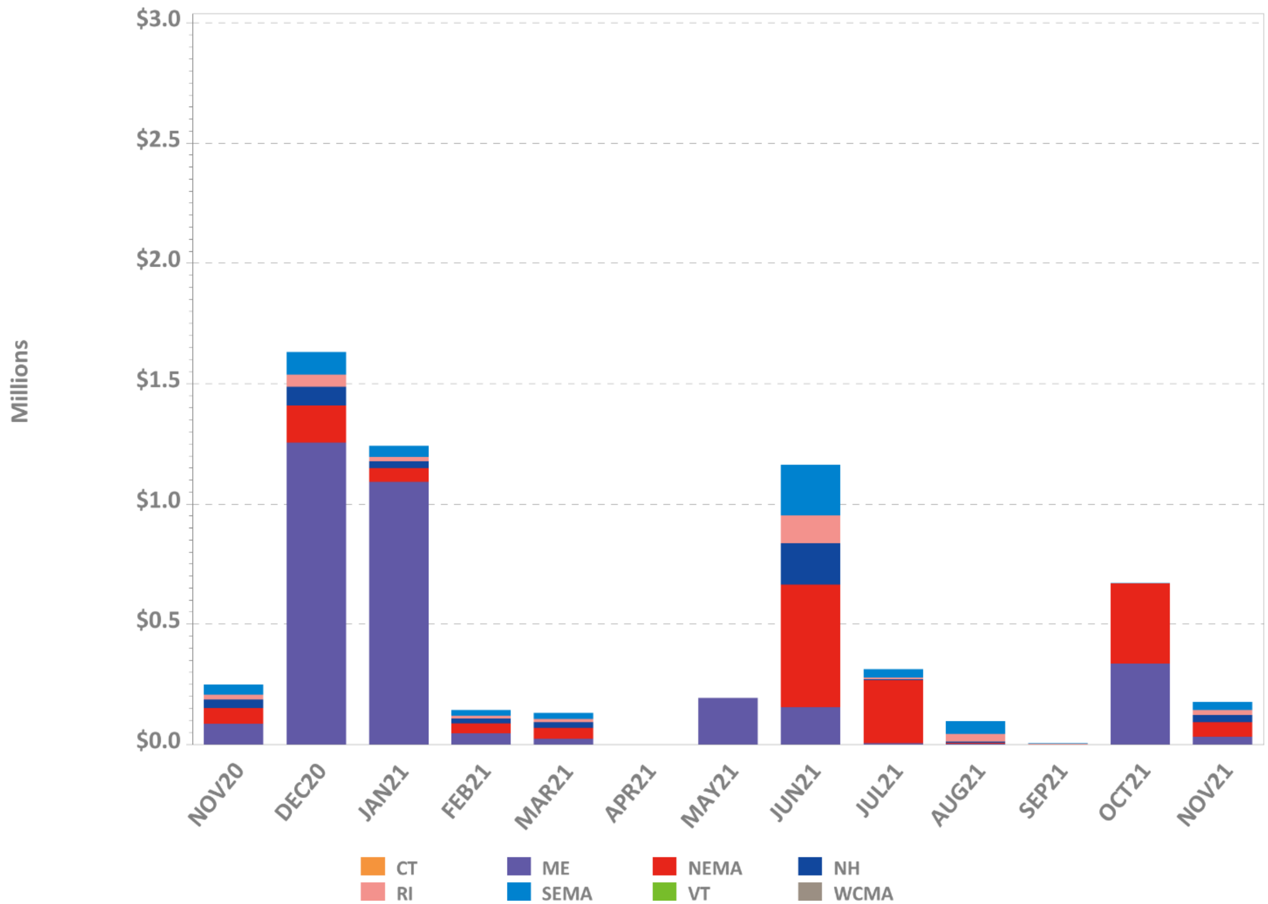
# RT First Contingency Charges by Deviation Type




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

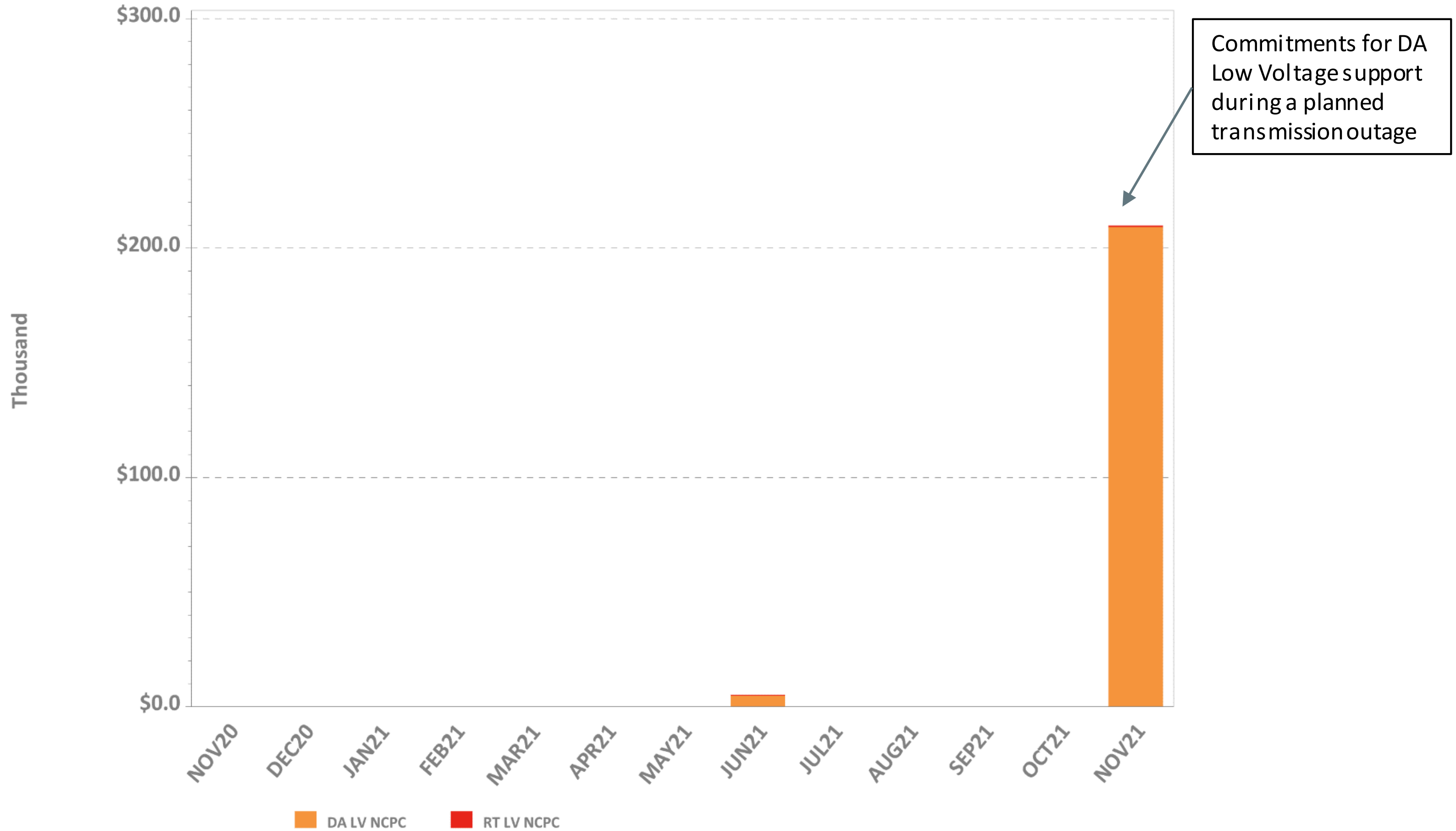
# LSCPR Charges by Reliability Region



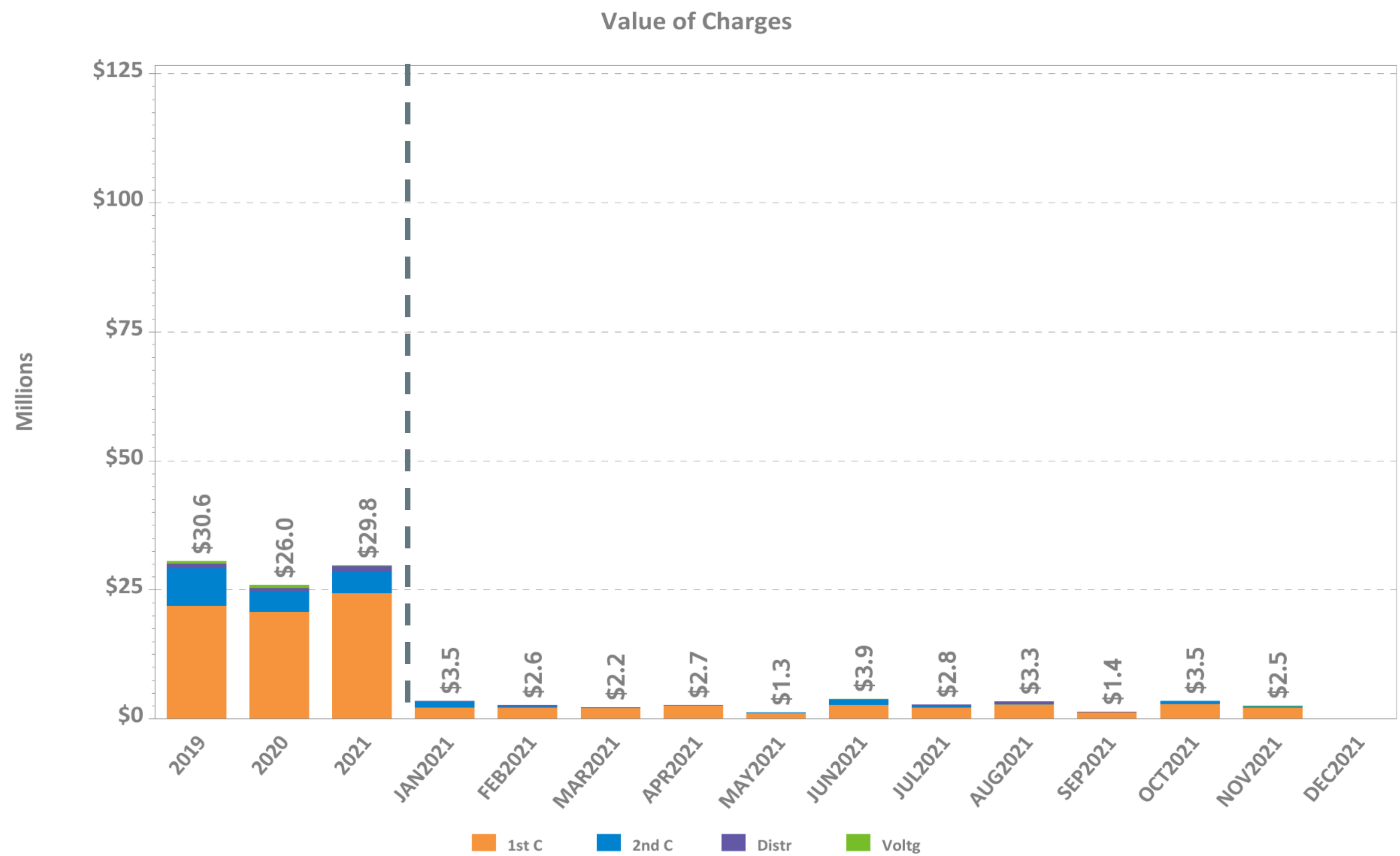

CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

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

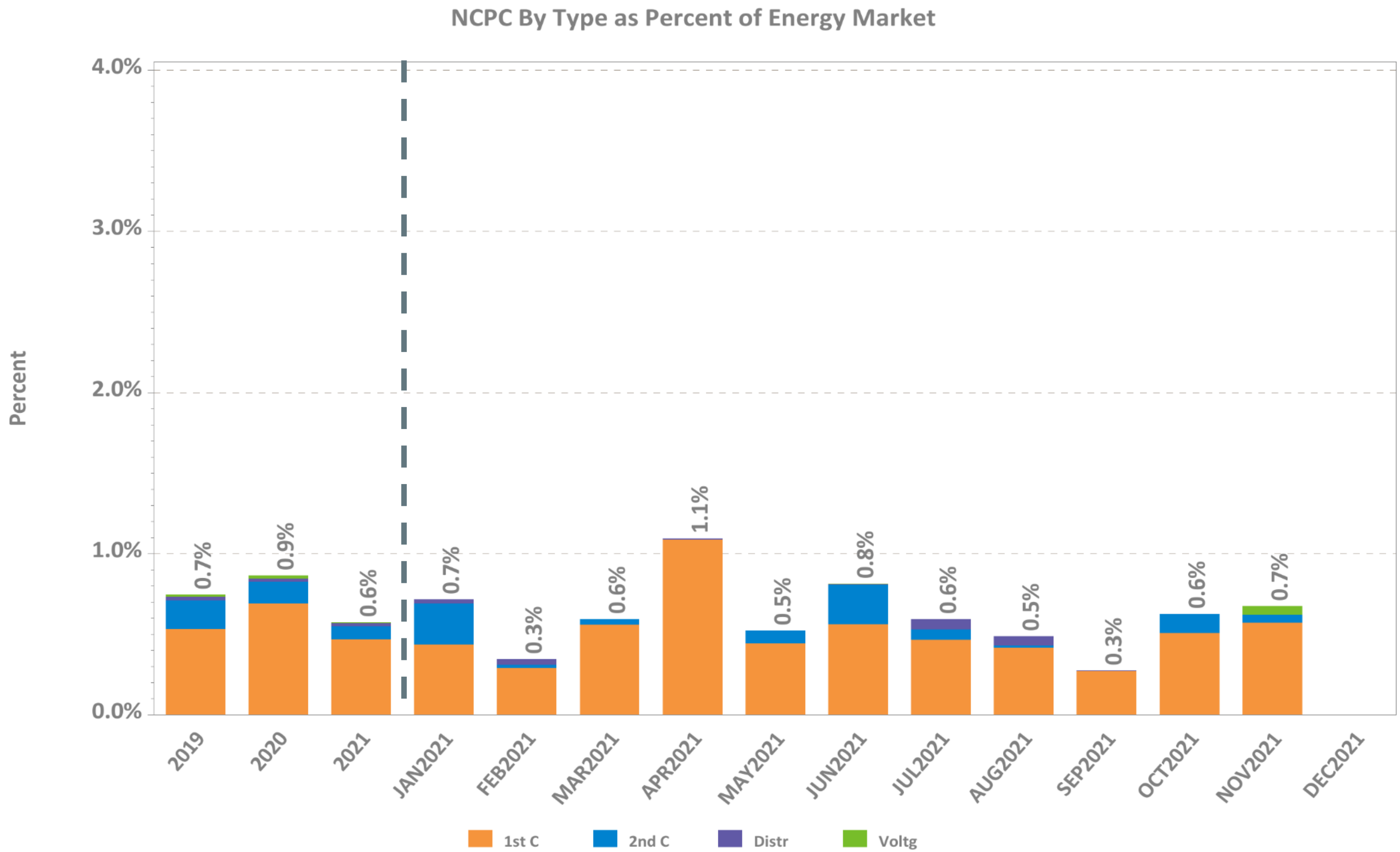
# NCPC Charges for Voltage Support and High Voltage Control



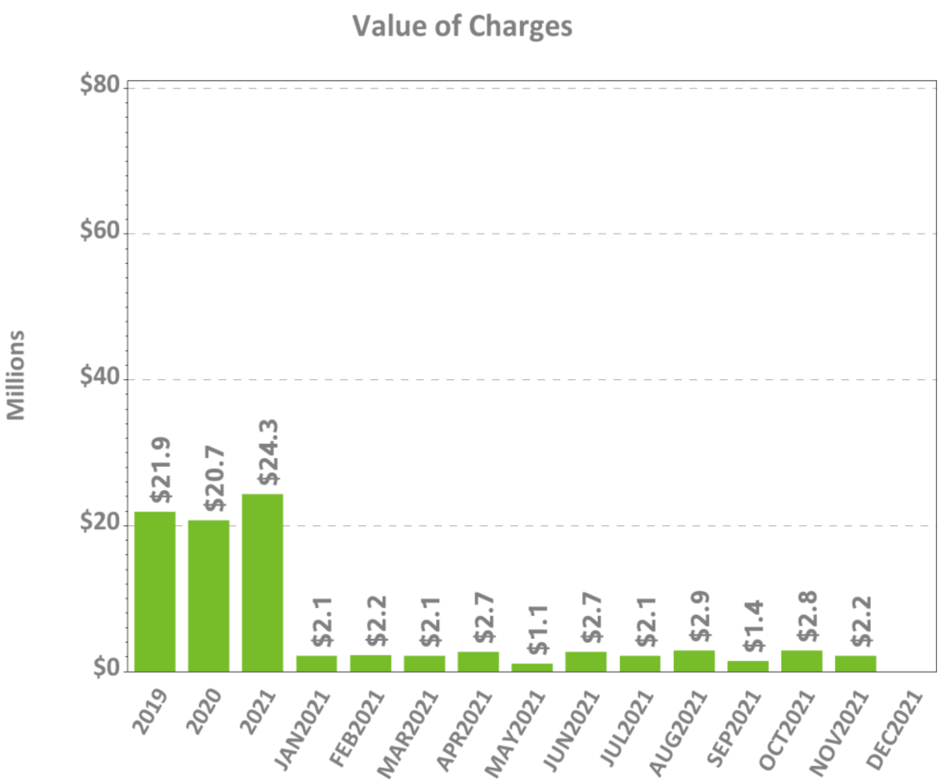
# NCPC Charges by Type

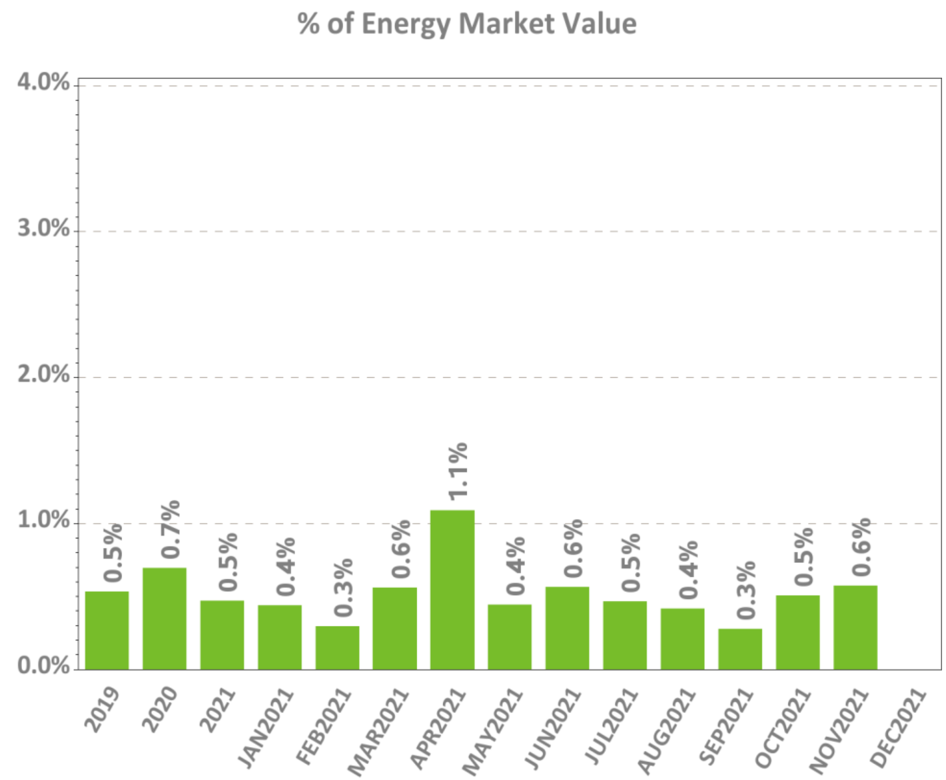


# NCPC Charges as Percent of Energy Market



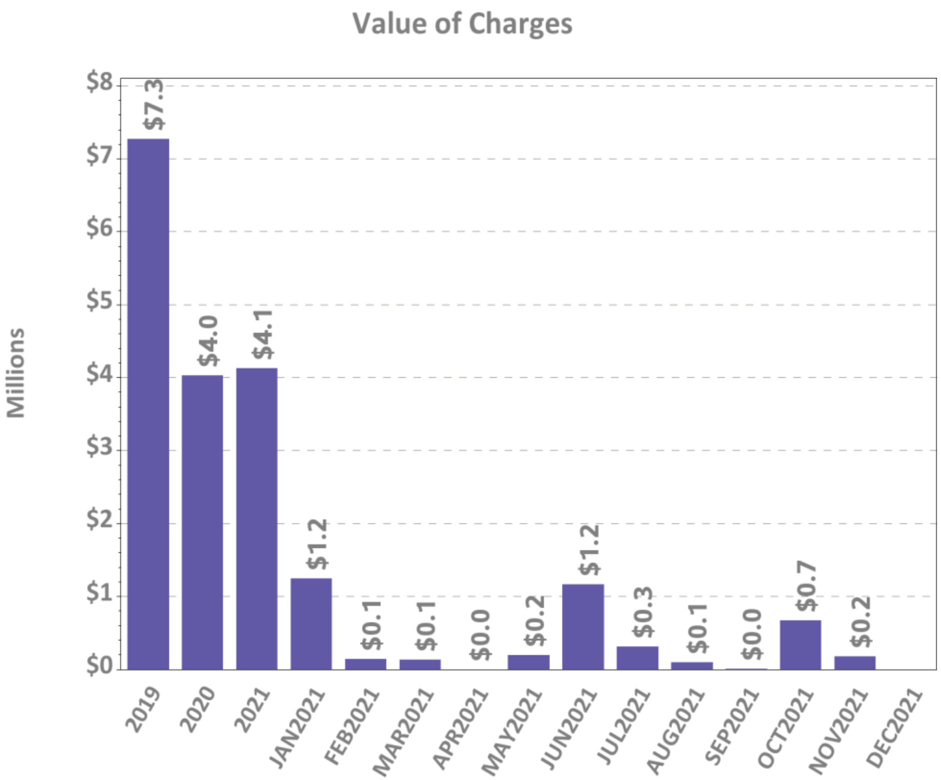
# First Contingency NCPC Charges

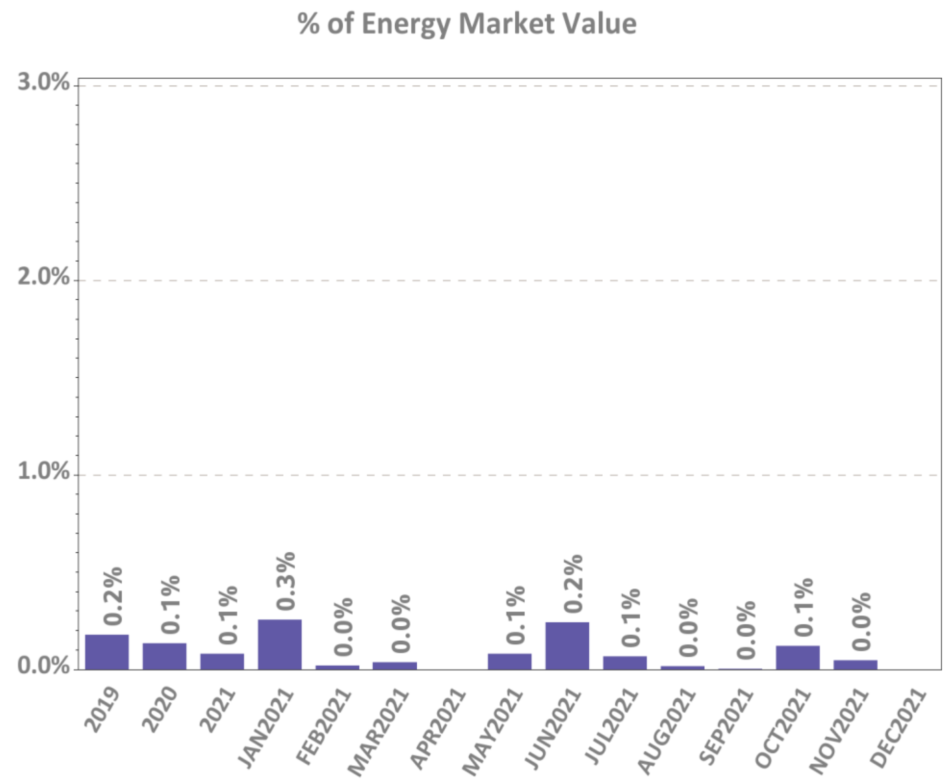



**Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market**

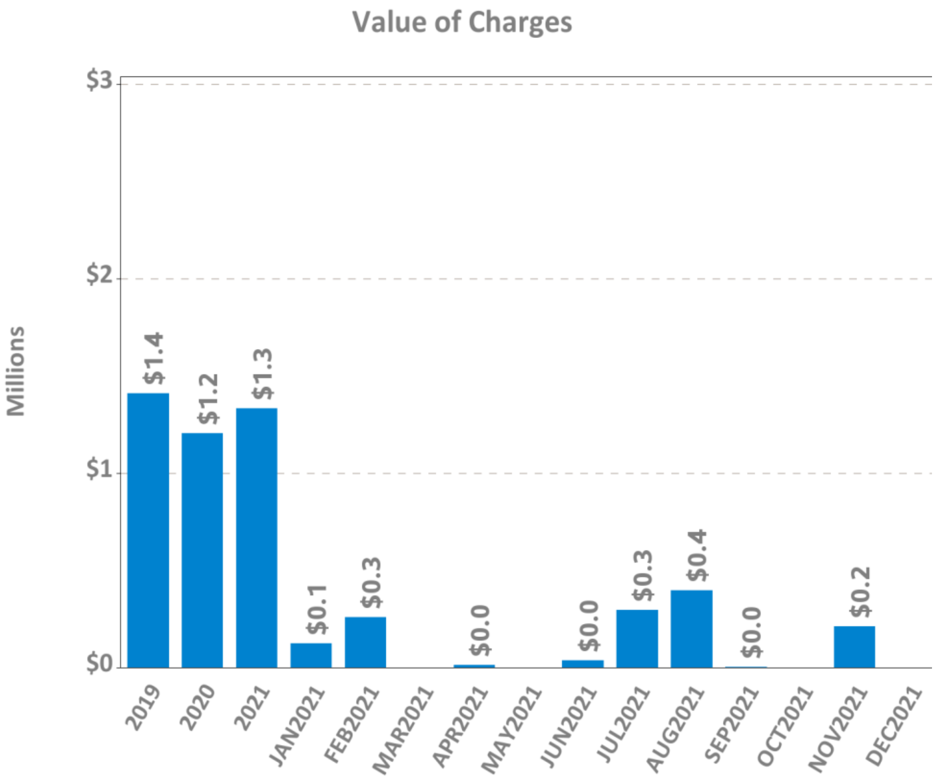
# Second Contingency NCPC Charges

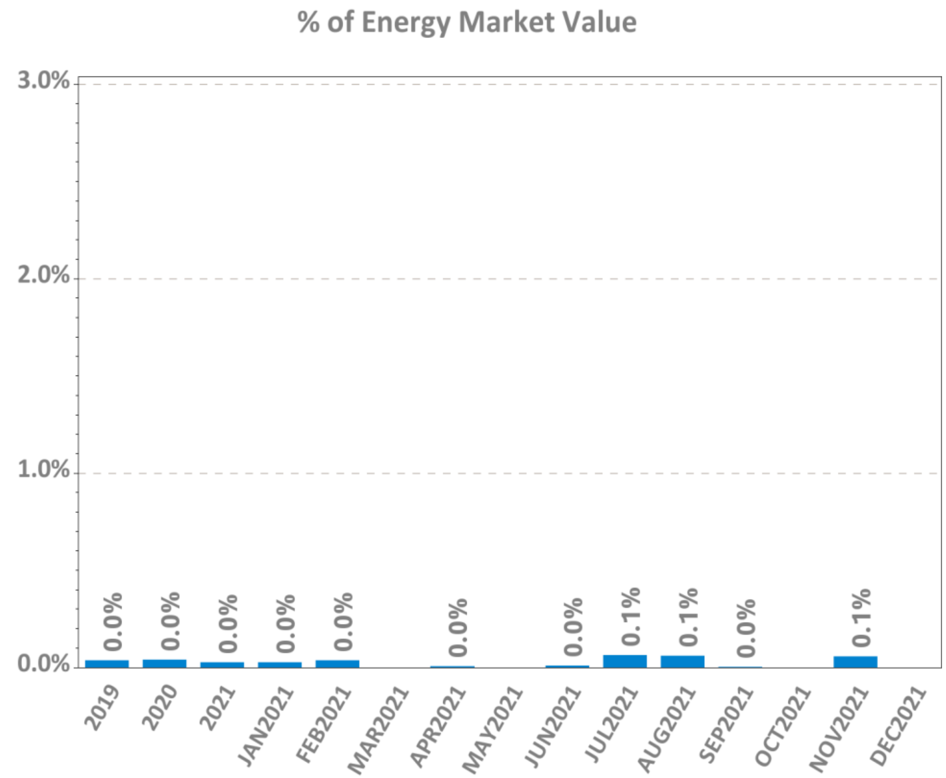



**Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market**

# 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

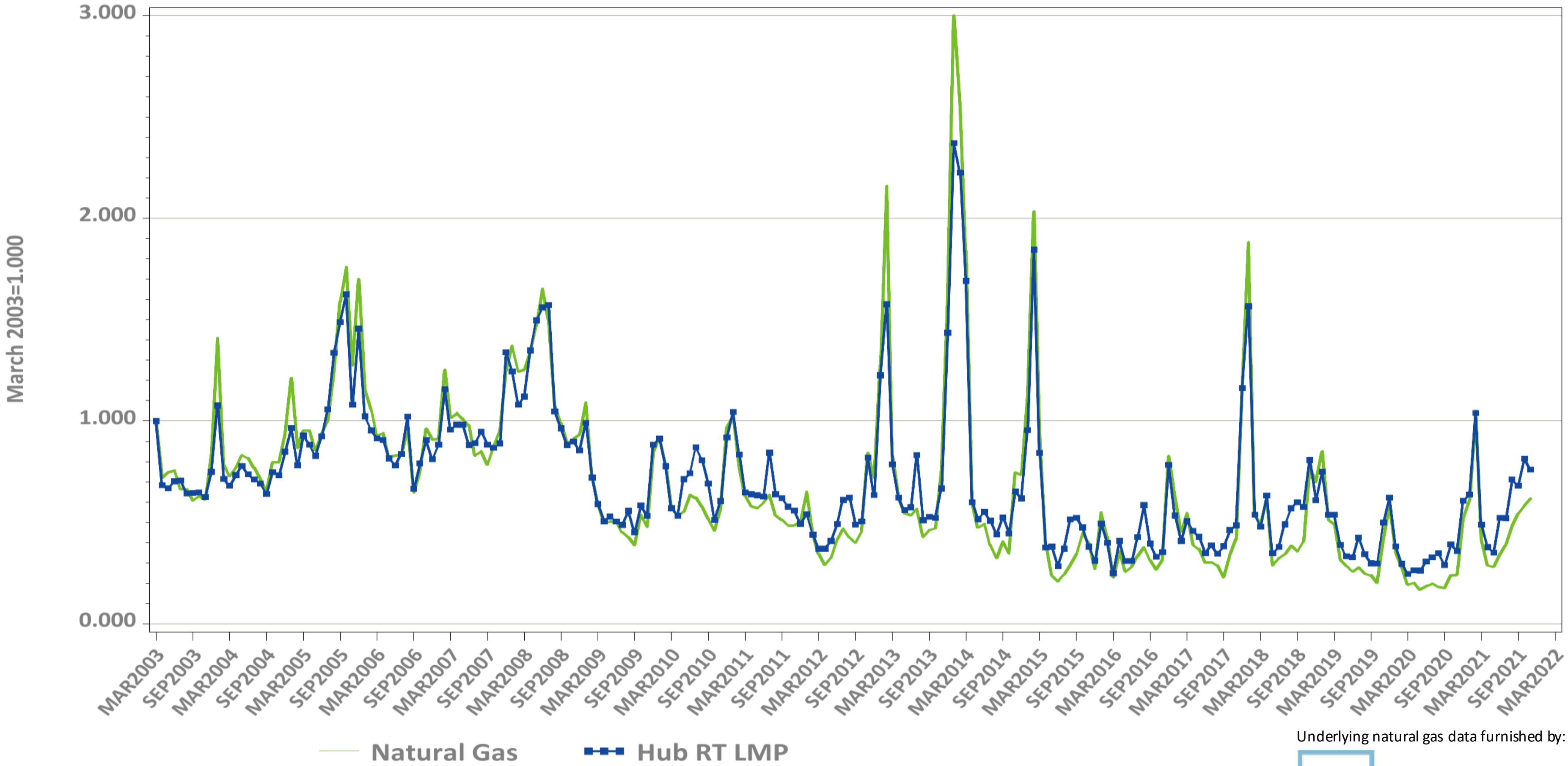
# DA vs. RT LMPs ($/MWh)

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% |

| November-20 | NEMA | CT | ME | NH | VT | RI | SEMA | WCMA | Hub |
|---|---|---|---|---|---|---|---|---|---|
| Day-Ahead | $25.51 | $24.21 | $25.37 | $25.37 | $24.32 | $25.01 | $25.48 | $25.11 | $25.12 |
| Real-Time | $24.90 | $24.10 | $24.52 | $24.82 | $23.98 | $24.42 | $24.87 | $24.62 | $24.64 |
| RT Delta % | -2.4% | -0.4% | -3.3% | -2.2% | -1.4% | -2.4% | -2.4% | -1.9% | -1.9% |
| November-21 | NEMA | CT | ME | NH | VT | RI | SEMA | WCMA | Hub |
| Day-Ahead | $53.11 | $49.98 | $51.71 | $52.80 | $50.59 | $52.05 | $52.72 | $52.02 | $52.03 |
| Real-Time | $52.72 | $51.04 | $51.57 | $52.58 | $51.30 | $51.64 | $52.31 | $52.25 | $52.22 |
| RT Delta % | -0.7% | 2.1% | -0.3% | -0.4% | 1.4% | -0.8% | -0.8% | 0.4% | 0.4% |
| Annual Diff. | NEMA | CT | ME | NH | VT | RI | SEMA | WCMA | Hub |
| Yr over Yr DA | 108.2% | 106.5% | 103.8% | 108.1% | 108.0% | 108.1% | 106.9% | 107.2% | 107.1% |
| Yr over Yr RT | 111.8% | 111.7% | 110.3% | 111.8% | 113.9% | 111.5% | 110.4% | 112.2% | 112.0% |

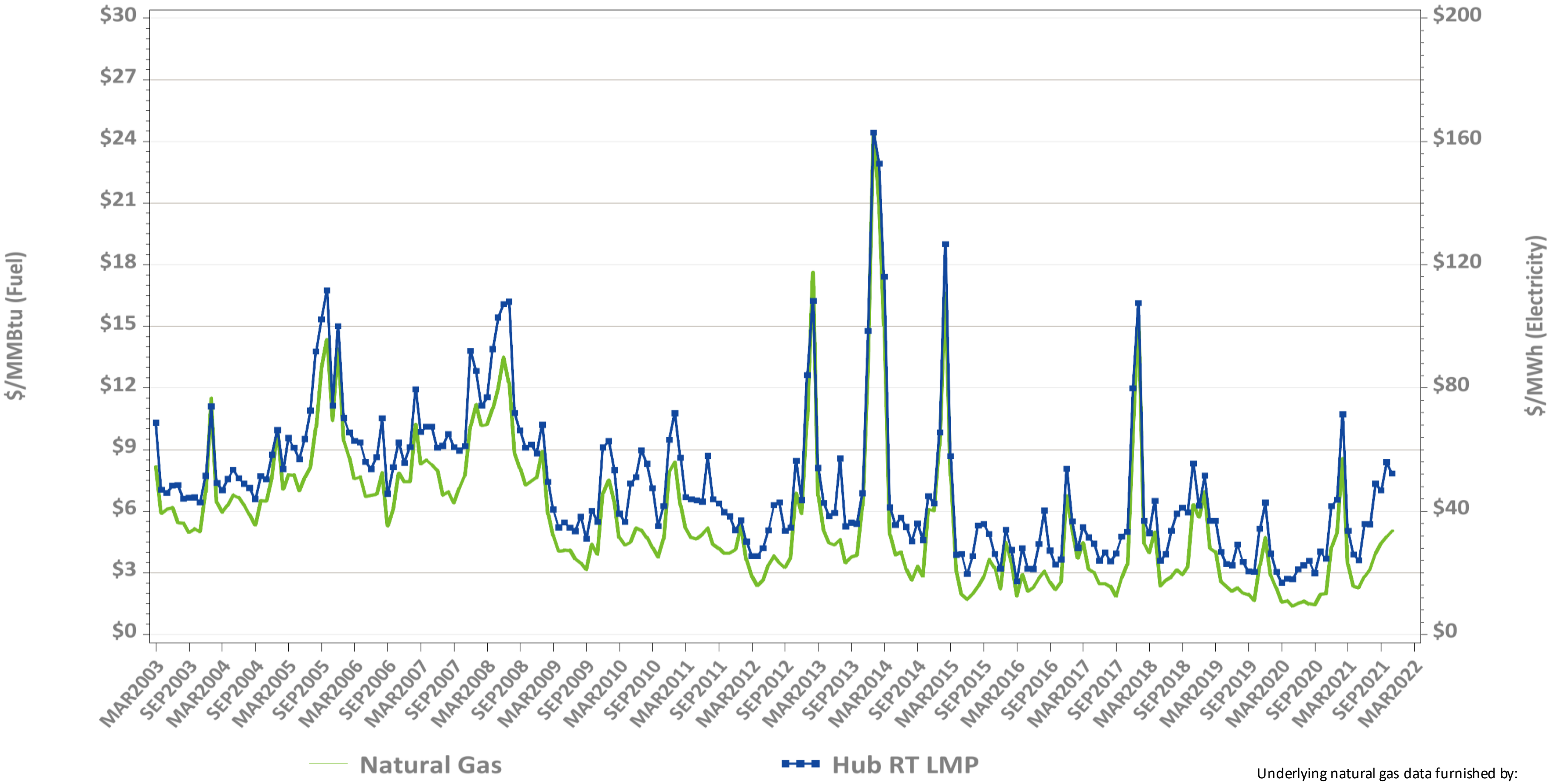
# Monthly Average Fuel Price and RT Hub LMP Indexes




Underlying natural gas data furnished by:

ice Global markets in clear view

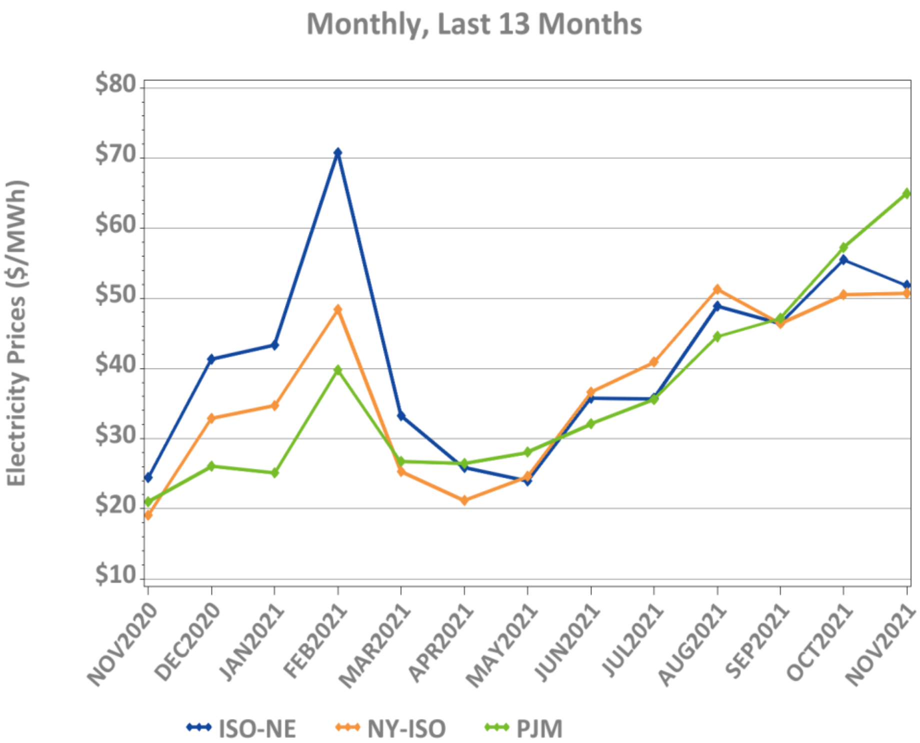
# Monthly Average Fuel Price and RT Hub LMP



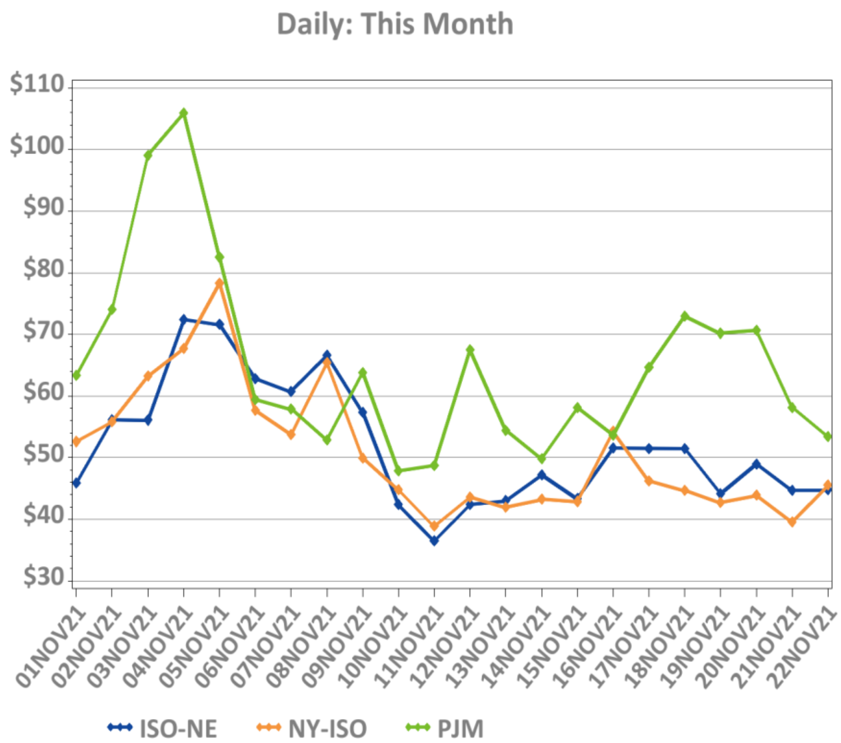

Underlying natural gas data furnished by:

ice Global markets in clear view

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

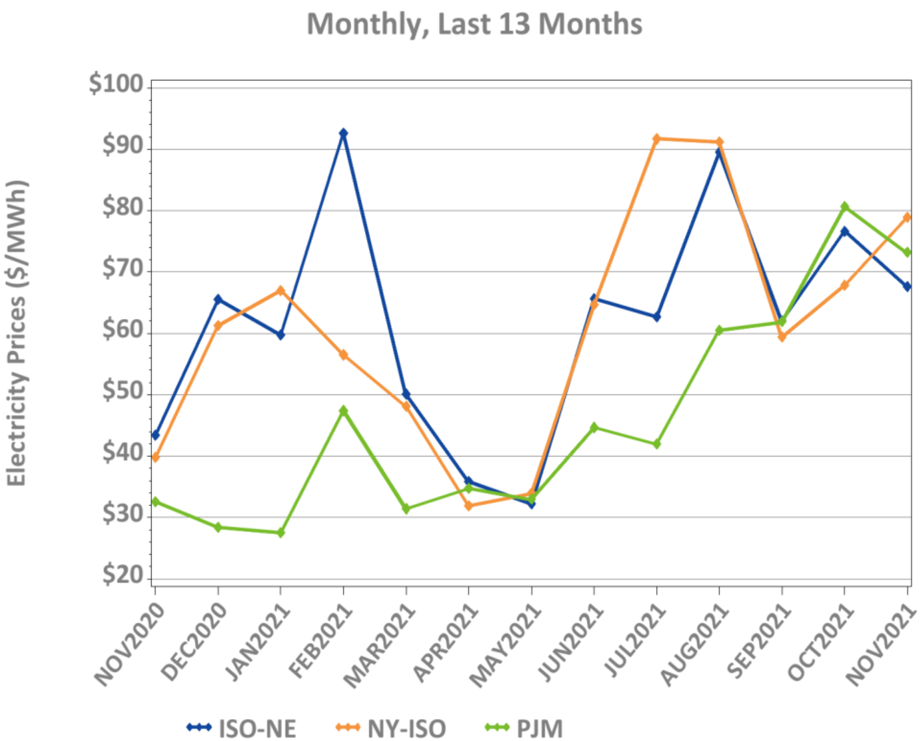


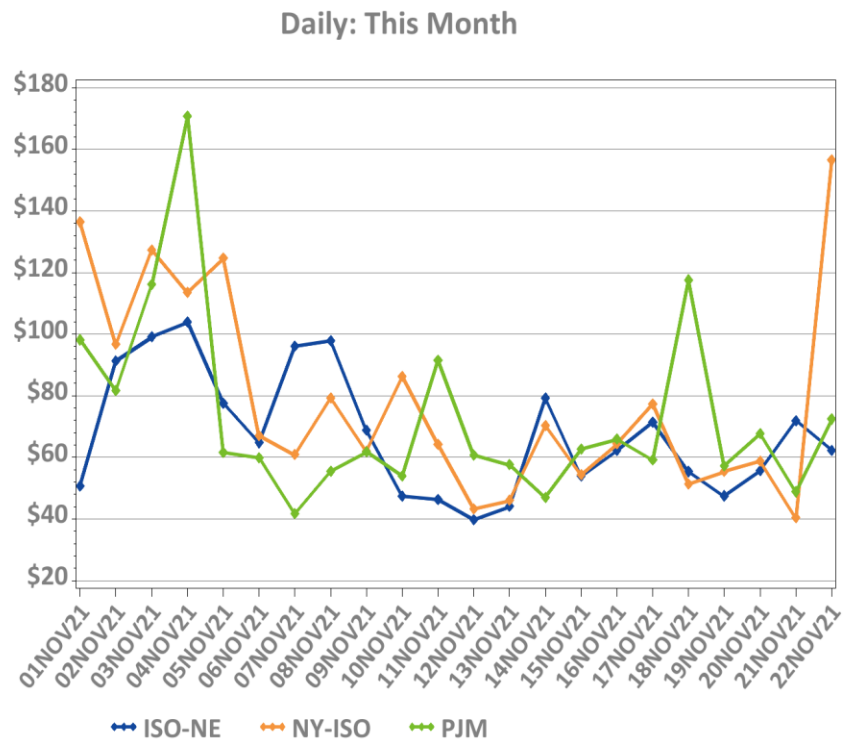

*Note: Hourly average prices are shown.




*Note: Hourly average prices are shown.

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



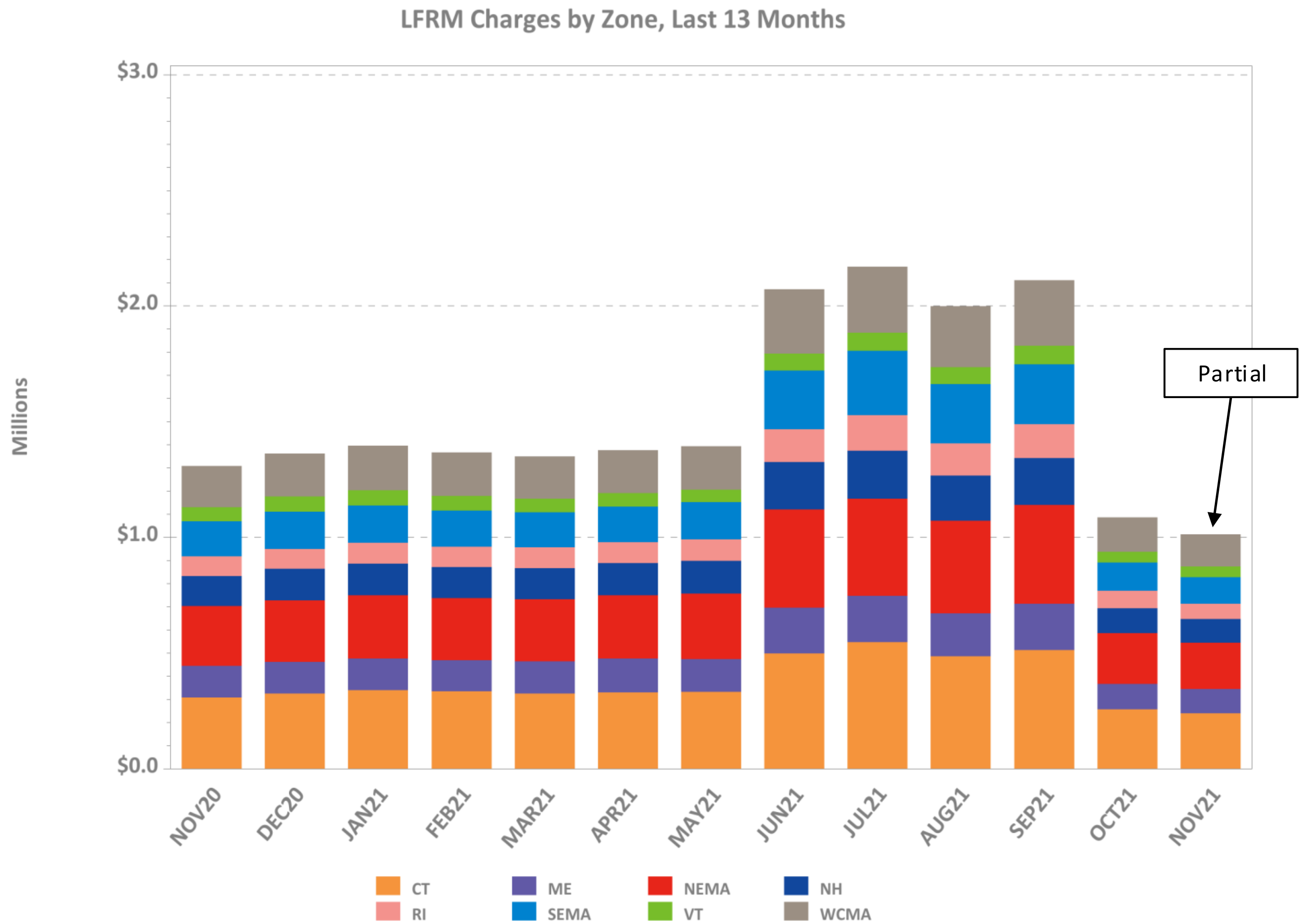

***Forecasted New England daily peak hours reflected**

# Reserve Market Results – November 2021

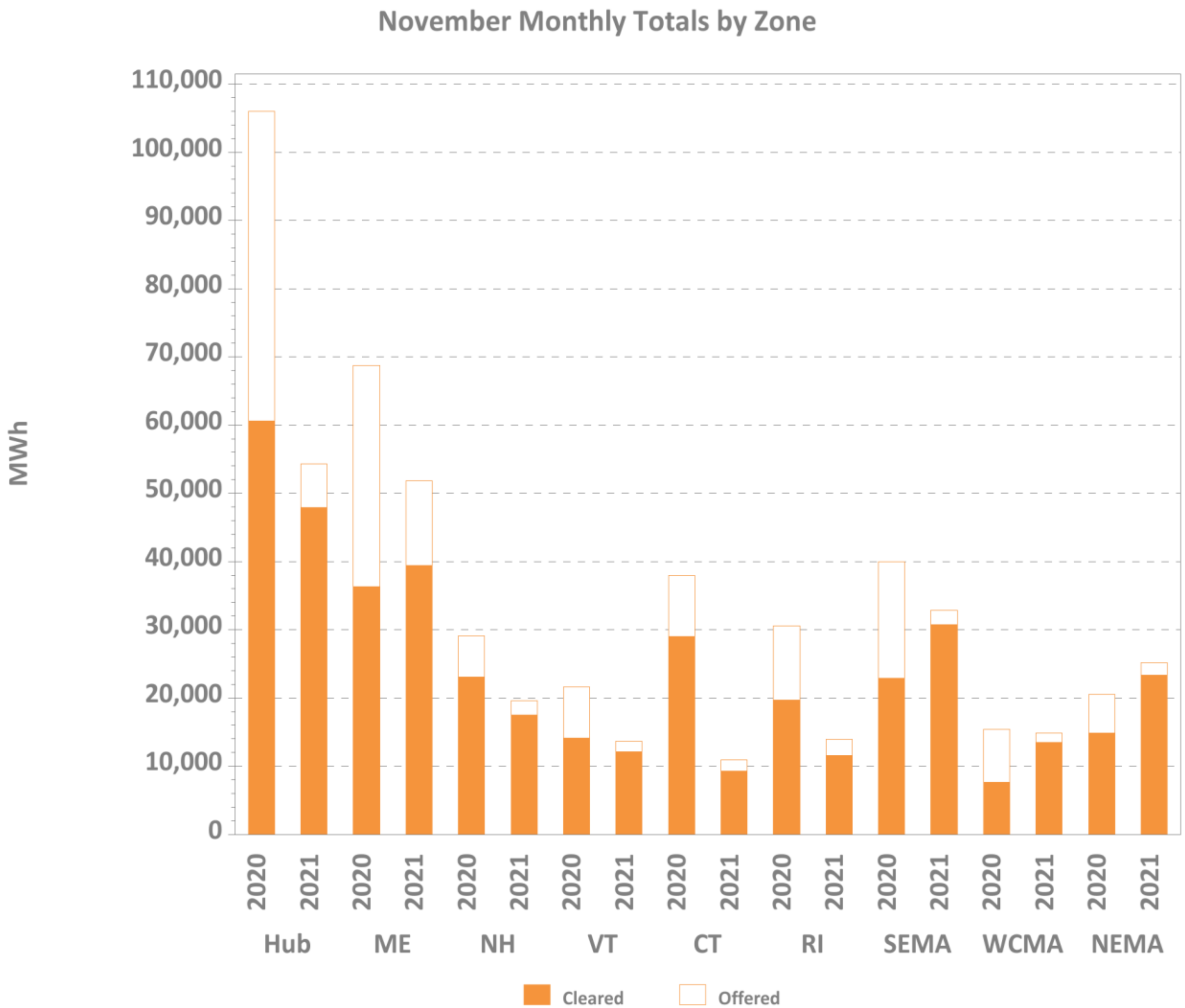
- Maximum potential Forward Reserve Market payments of $1M were reduced by credit reductions of $23K, failure-to-reserve penalties of $34K and no failure-to-activate penalties, resulting in a net payout of $0.9M or 94% of maximum
  - Rest of System: $0.68M/0.74M (93%)
  - Southwest Connecticut: $0.03M/0.03M (100%)
  - Connecticut: $0.24M/0.24M (99%)
  - NEMA: $2K/4K (51%)
- $332K total Real-Time credits were not reduced by any Forward Reserve Energy Obligation Charges for a net of $332K in Real-Time Reserve payments
  - Rest of System: 159 hours, $242K
  - Southwest Connecticut: 159 hours, $42K
  - Connecticut: 159 hours, $32K
  - NEMA: 159 hours, $16K

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.

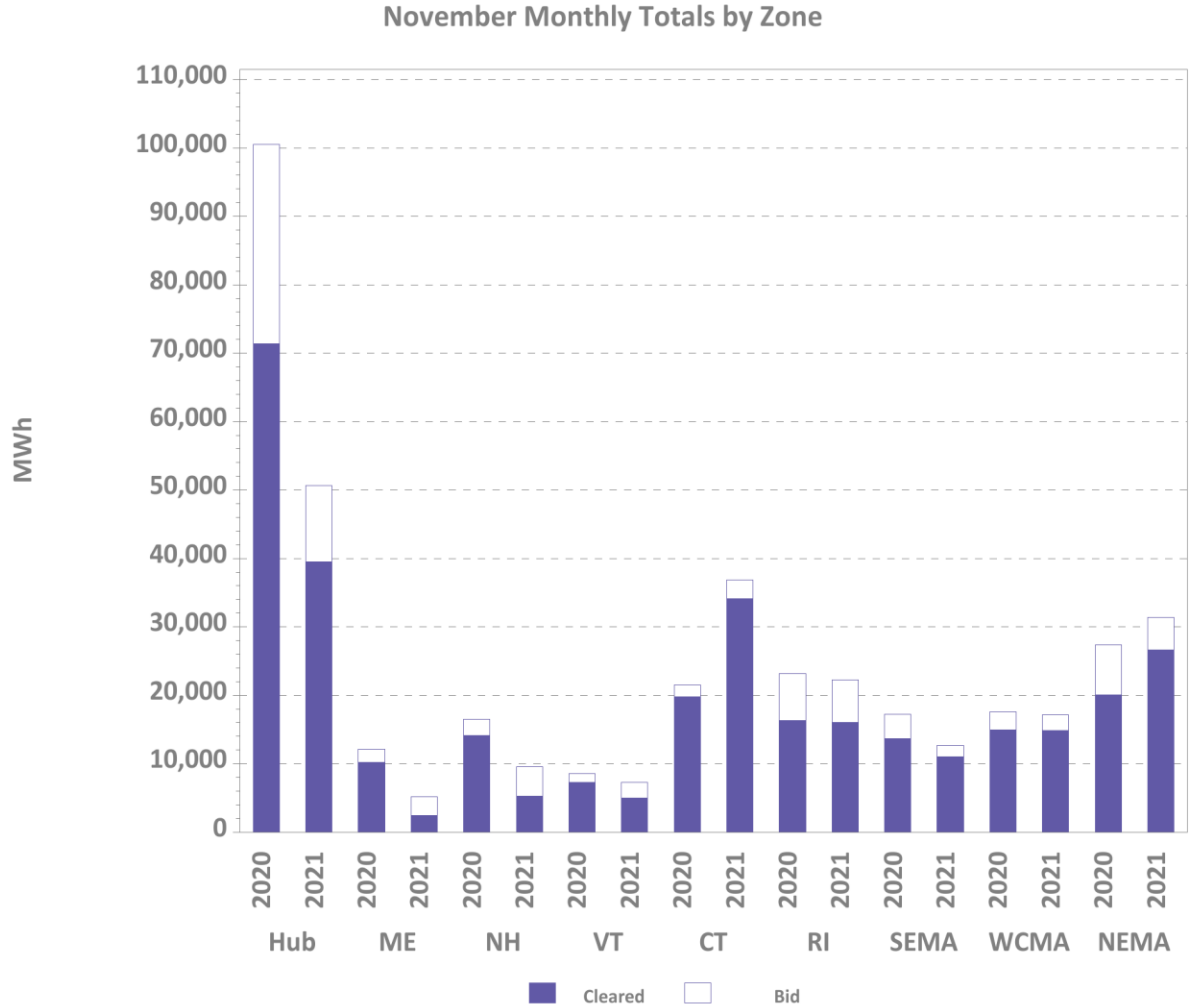
# LFRM Charges to Load by Load Zone ($)



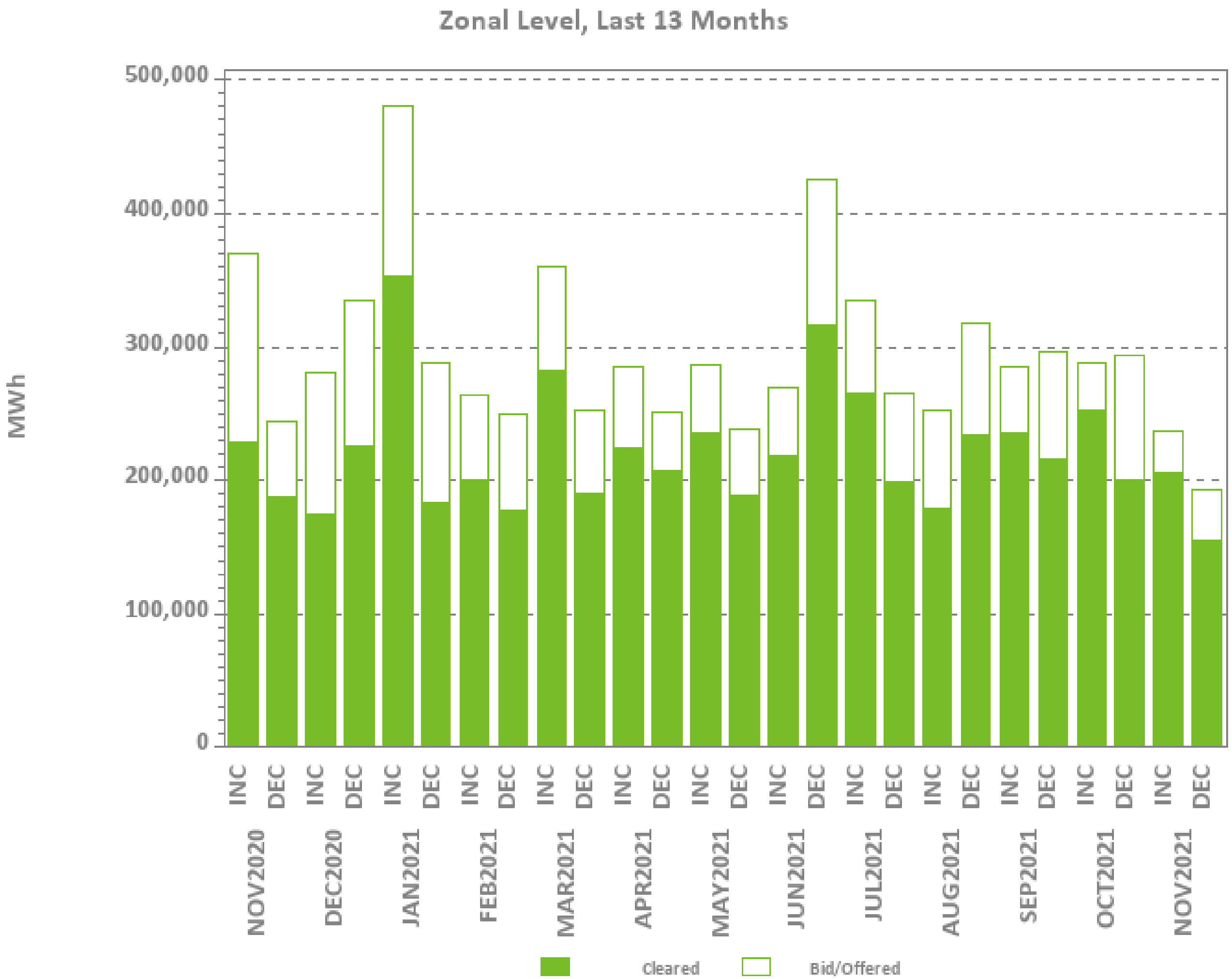
# Zonal Increment Offers and Cleared Amounts



# Zonal Decrement Bids and Cleared Amounts

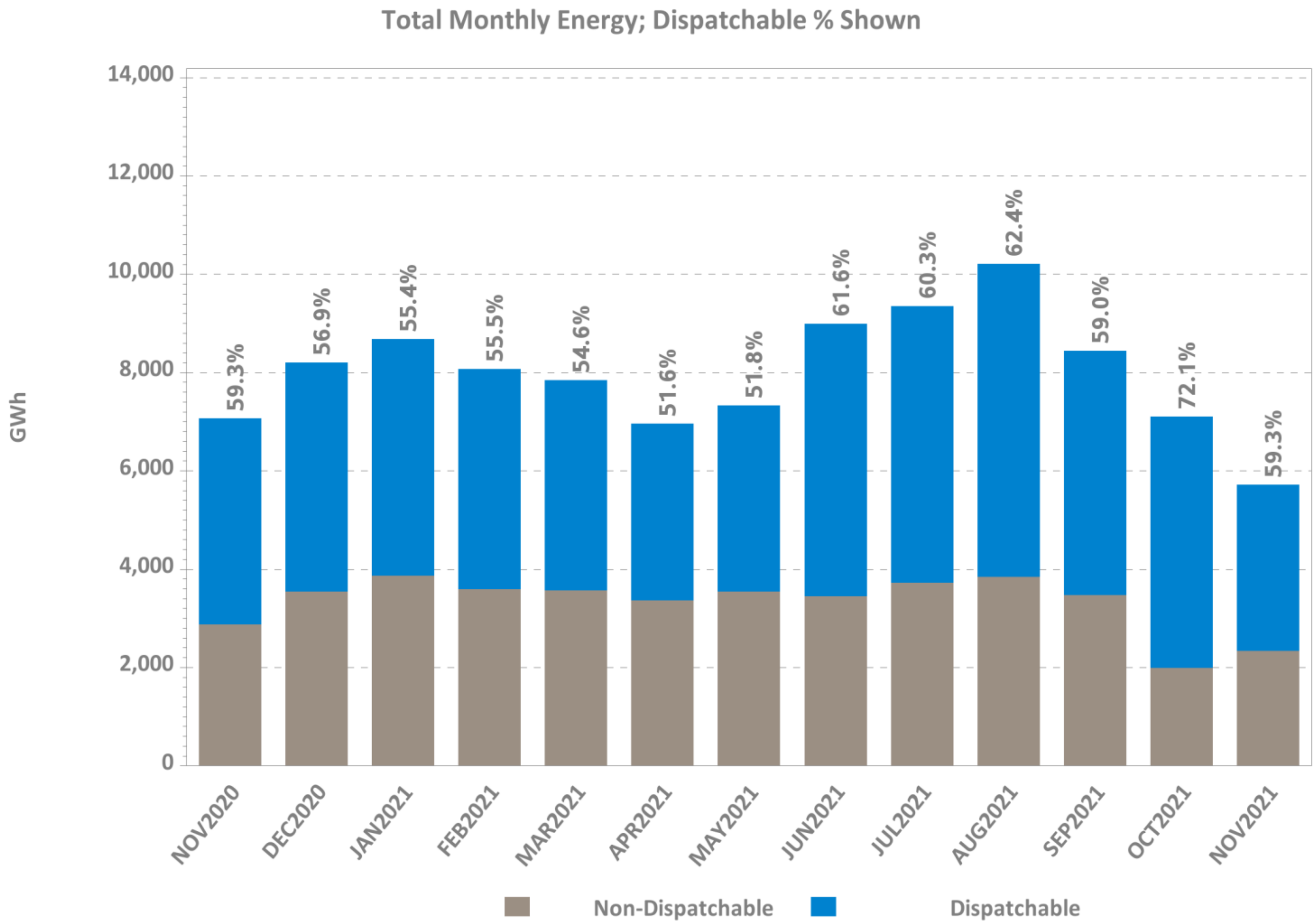


# Total Increment Offers and Decrement Bids




**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)

# Planning Advisory Committee (PAC)

- December 15 PAC Meeting Agenda Topics*
  - 2021 Economic Study: Future Grid Reliability Study
    - Preliminary Production Cost & Ancillary Services - Part 4
    - High-Level Transmission Analysis - Part 2
    - Probabilistic Resource Availability & Resource Adequacy Screen Results - Part 2
  - National Grid Asset Condition Projects
    - V-174 115 kV Line Optical Ground Wire Installation and Asset Condition Replacement
    - 115 kV M-139/N-140 Lines Pilot Protection Schemes
  - Eversource Asset Condition Projects
    - 115 kV and 345 kV Structure Replacements
    - Timber Swamp 345 kV Breaker Replacement
    - Edgar Station 150 Brown Glass and Obsolete Equipment Replacement

* 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 transmission planning 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 final revisions to the Transmission Planning Technical Guide reflecting these changes on 9/30/21
- CEII supplement to the PAC presentations was released on 10/5/21; full written report on the pilot study is expected to be released in late 2021
- Future testing will focus on transient stability modeling and performance criteria

# 2050 Transmission Study

- A meeting with the states was held on 10/15/21 to review the draft study scope
- The draft study scope was discussed with the PAC on 11/17/21

# Economic Studies

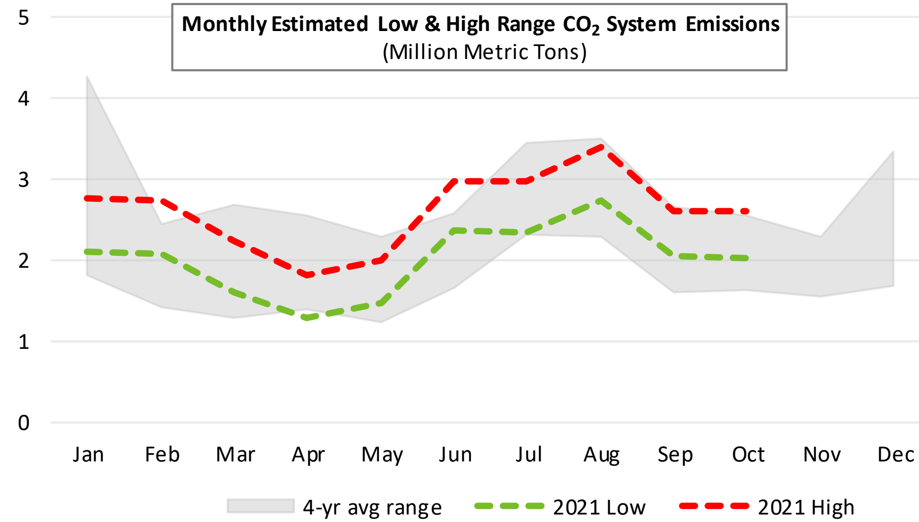
- 2020 Economic Study Request
  - Study proponent is National Grid
  - Study simulations are complete, and results have been presented to PAC
    - Draft report expected by the end of 2021
- 2021 Economic Study Request
  - Also known as Future Grid Reliability Study – Phase 1 (FGRS)
  - Study proponent is NEPOOL
  - Additional ancillary services and initial resource adequacy screen results were discussed at the November 17 PAC meeting
  - The ISO will seek feedback from the MC/RC at the December 15 meeting for the high-level transmission, ancillary services, and resource adequacy screen analyses

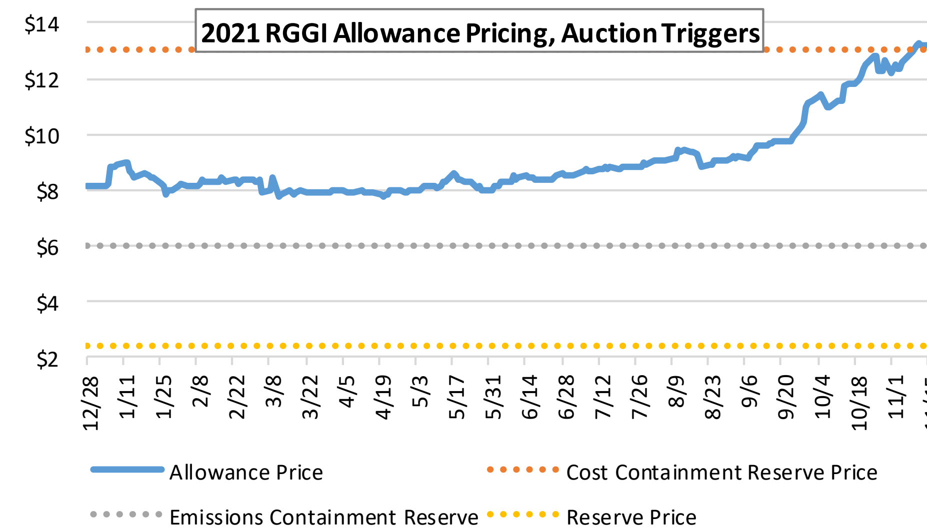
# Future Grid Reliability Study (FGRS)

- 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
- Phase 2
  - Studies include: Revenue Sufficiency Analysis and Transmission Security
  - Studies will be delayed as the Pathways and 2050 Transmission studies are further defined

# Environmental Matters – System $CO_2$ Emissions Up, Compliance Cost Trends Higher

- New England January - October 2021 estimated system $CO_2$ emissions range between **20** and **26** million metric tons (MMT)
  - January - October four-year average (2017-2020) $CO_2$ emissions range between **16.5** and **28.9** MMT
- RGGI compliance costs increasing for affected generators
  - Average allowance prices up 44% between 2020 and 2021 YTD
  - Spot prices up from $**8.11** (12/28/20) to $**13.17** (as of 11/15/21)
  - At $13, compliance costs increase 68% year-to-year for a natural-gas-fired generator, from $**2.88**/MWh (2020) to $**4.85**/MWh (2021)




**RGGI Annual Compliance Costs by Fuel Type ($/MWh)**

| | 2019 | 2020 | 2021 |
|---|---|---|---|
| Natural Gas | $2.51 | $2.88 | $4.85 |
| No. 2 Oil | $5.19 | $5.95 | $12.24 |
| No. 6 Oil | $5.03 | $5.77 | $11.88 |
| Coal | $5.67 | $6.50 | $13.39 |
| RGGI average price ($/short ton) | $5.51 | $6.31 | $9.07 |

RGGI – Regional Greenhouse Gas Initiative

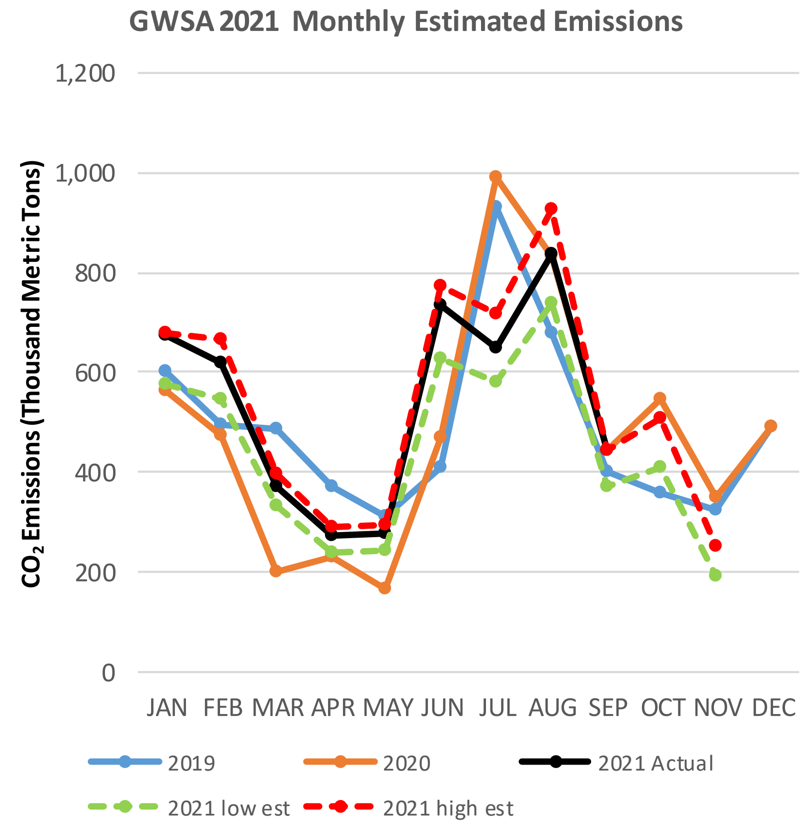
# Environmental Matters – Massachusetts $CO_2$ Generator Emissions Cap

## 2021 $CO_2$ Emissions, Allowance Prices Trending Higher vs. 2020

- As of 11/14/21, estimated GWSA $CO_2$ emissions range between **4.7** to **5.8** MMT (58% to 72%) of 2021 cap (8.28 MMT)
- Last 2021 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

GWSA - Global Warming Solutions Act

## 2019-2021 Estimated Monthly Emissions (Thousand Metric Tons)



# RSP Project Stage Descriptions

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

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

# Greater Boston Projects

## *Status as of 11/17/2021*

*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-23 | 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 11/17/2021*

*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 11/17/2021*

*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 11/17/2021*

*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 | Dec-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 11/17/2021*

*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 11/17/2021*

*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 11/17/2021*

*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 11/17/2021*

*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 11/17/2021*

*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 11/17/2021*

*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 11/17/2021*

*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 11/17/2021*

*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 11/17/2021*

*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 11/17/2021*

*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-22 | 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 11/17/2021*

*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 | 2 |
| 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 11/17/2021*

*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 |

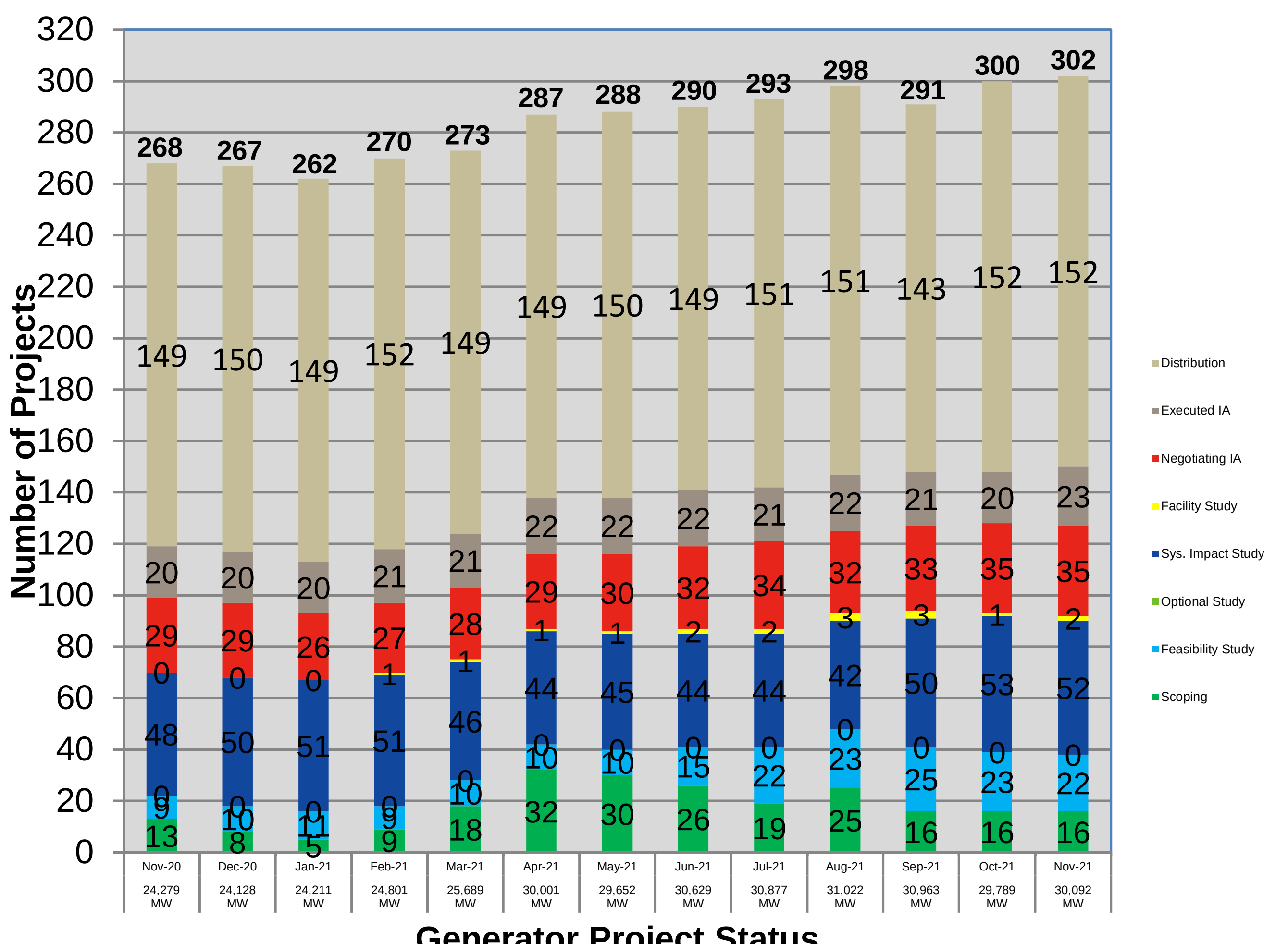
# Upper Maine Solution Projects, cont.

*Status as of 11/17/2021*

*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 |

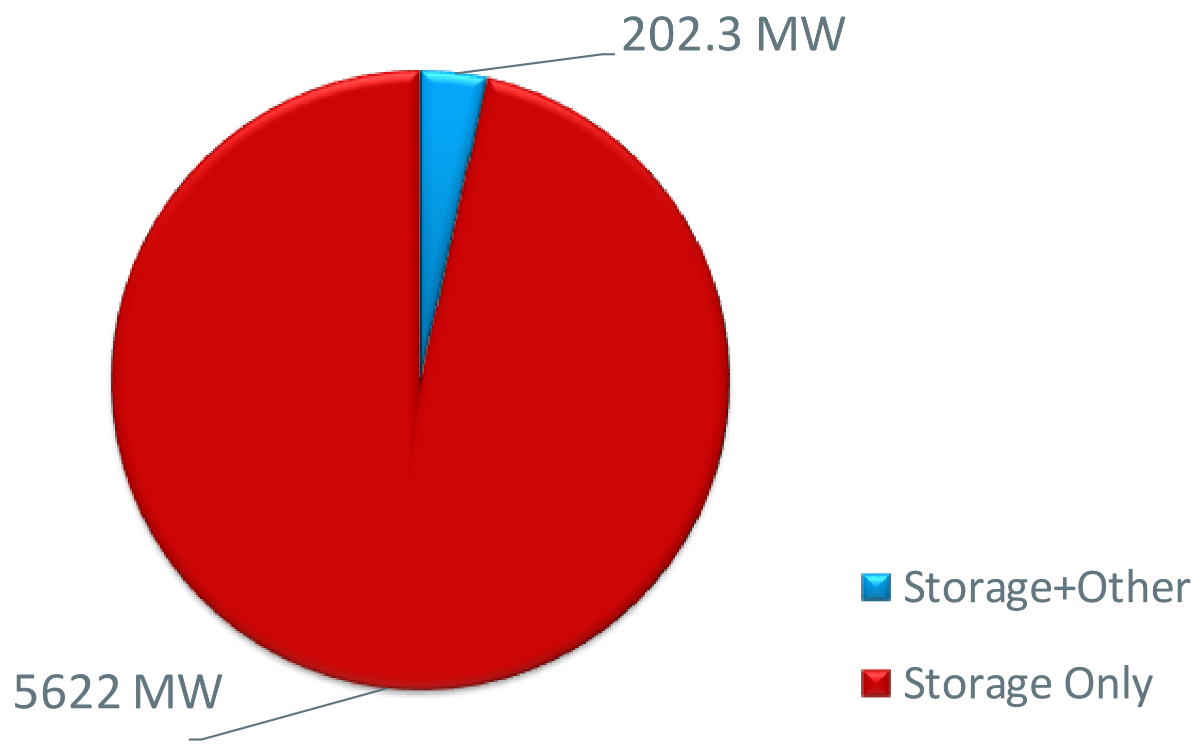
# Status of Tariff Studies




Note: November 2021 is based on partial data.
As of November 2021: 1 ETU in Scoping, 2 in FS, 1 in SIS, 0 in OIS, 1 in FAC, 1 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 November 22, 2021)

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



# OPERABLE CAPACITY ANALYSIS

*Winter 2021/22 Analysis*

# 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] | 29,777 | 32,096 |
| Active Demand Capacity Resource (+) [5] | 541 | 393 |
| External Node Available Net Capacity, CSO imports minus firm capacity exports (+) | 1,143 | 1,143 |
| Non Commercial Capacity (+) | 40 | 40 |
| Non Gas-fired Planned Outage MW (-) | 66 | 495 |
| 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) | 24,900 | 26,090 |
| 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 | 2,885 | 4,075 |

[1] Operable Capacity is based on data as of **November 22, 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 **November 22, 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.

# Winter 2021/22 Operable Capacity Analysis

| 90/10 Load Forecast | Jan. - 2022[2] CSO (MW) | Jan. - 2022[2] SCC (MW) |
|---|---|---|
| Operable Capacity MW [1] | 29,777 | 32,096 |
| Active Demand Capacity Resource (+) [5] | 541 | 393 |
| External Node Available Net Capacity, CSO imports minus firm capacity exports (+) | 1,143 | 1,143 |
| Non Commercial Capacity (+) | 40 | 40 |
| Non Gas-fired Planned Outage MW (-) | 66 | 495 |
| 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) | 24,089 | 25,160 |
| 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 | 1,435 | 2,506 |

[1] Operable Capacity is based on data as of **November 22, 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 **November 22, 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.

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

## ISO-NE OPERABLE CAPACITY ANALYSIS

### *November 29, 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: 11/22/2021

| 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 |
| 12/11/2021 | 29726 | 474 | 1143 | 33 | 740 | 298 | 3200 | 2283 | 24855 | 18900 | 2305 | 21205 | 3650 | N | Winter 2021/2022 |
| 12/18/2021 | 29726 | 474 | 1143 | 33 | 649 | 102 | 3200 | 2692 | 24733 | 18911 | 2305 | 21216 | 3517 | N | Winter 2021/2022 |
| 12/25/2021 | 29726 | 474 | 1143 | 33 | 316 | 93 | 3200 | 3048 | 24719 | 18973 | 2305 | 21278 | 3441 | N | Winter 2021/2022 |
| 1/1/2022 | 29777 | 541 | 1143 | 40 | 162 | 0 | 2800 | 3740 | 24799 | 19246 | 2305 | 21551 | 3248 | N | Winter 2021/2022 |
| 1/8/2022 | 29777 | 541 | 1143 | 40 | 66 | 0 | 2800 | 3735 | 24900 | 19710 | 2305 | 22015 | 2885 | Y | Winter 2021/2022 |
| 1/15/2022 | 29777 | 541 | 1143 | 40 | 65 | 0 | 2800 | 3590 | 25046 | 19710 | 2305 | 22015 | 3031 | N | Winter 2021/2022 |
| 1/22/2022 | 29777 | 541 | 1143 | 40 | 40 | 0 | 2800 | 3141 | 25520 | 19710 | 2305 | 22015 | 3505 | N | Winter 2021/2022 |
| 1/29/2022 | 29784 | 541 | 1135 | 40 | 339 | 0 | 3100 | 2842 | 25219 | 19488 | 2305 | 21793 | 3426 | N | Winter 2021/2022 |
| 2/5/2022 | 29784 | 541 | 1135 | 40 | 375 | 0 | 3100 | 2543 | 25482 | 19222 | 2305 | 21527 | 3955 | N | Winter 2021/2022 |
| 2/12/2022 | 29784 | 541 | 1135 | 40 | 330 | 0 | 3100 | 2244 | 25826 | 19193 | 2305 | 21498 | 4328 | N | Winter 2021/2022 |
| 2/19/2022 | 29784 | 541 | 1135 | 40 | 325 | 0 | 3100 | 1795 | 26280 | 18931 | 2305 | 21236 | 5044 | N | Winter 2021/2022 |
| 2/26/2022 | 29784 | 541 | 1135 | 40 | 380 | 0 | 3100 | 1496 | 26524 | 17944 | 2305 | 20249 | 6275 | N | Winter 2021/2022 |
| 3/5/2022 | 29784 | 541 | 1135 | 40 | 438 | 270 | 2200 | 927 | 27665 | 17596 | 2305 | 19901 | 7764 | N | Winter 2021/2022 |
| 3/12/2022 | 29784 | 541 | 1135 | 40 | 738 | 718 | 2200 | 0 | 27844 | 17400 | 2305 | 19705 | 8139 | N | Winter 2021/2022 |
| 3/19/2022 | 29784 | 541 | 1135 | 40 | 1252 | 963 | 2200 | 0 | 27085 | 17036 | 2305 | 19341 | 7744 | N | Winter 2021/2022 |
| 3/26/2022 | 29760 | 540 | 1135 | 40 | 1713 | 757 | 2700 | 0 | 26305 | 16472 | 2305 | 18777 | 7528 | 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.

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

## ISO-NE OPERABLE CAPACITY ANALYSIS

*November 29, 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: 11/22/2021

| 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 |
| 12/11/2021 | 29726 | 474 | 1143 | 33 | 740 | 298 | 3200 | 3270 | 23868 | 19515 | 2305 | 21820 | 2048 | N | Winter 2021/2022 |
| 12/18/2021 | 29726 | 474 | 1143 | 33 | 649 | 102 | 3200 | 3811 | 23614 | 19527 | 2305 | 21832 | 1782 | N | Winter 2021/2022 |
| 12/25/2021 | 29726 | 474 | 1143 | 33 | 316 | 93 | 3200 | 4194 | 23573 | 19591 | 2305 | 21896 | 1677 | N | Winter 2021/2022 |
| 1/1/2022 | 29777 | 541 | 1143 | 40 | 162 | 0 | 2800 | 4415 | 24124 | 19872 | 2305 | 22177 | 1947 | N | Winter 2021/2022 |
| 1/8/2022 | 29777 | 541 | 1143 | 40 | 66 | 0 | 2800 | 4546 | 24089 | 20349 | 2305 | 22654 | 1435 | Y | Winter 2021/2022 |
| 1/15/2022 | 29777 | 541 | 1143 | 40 | 65 | 0 | 2800 | 4338 | 24298 | 20349 | 2305 | 22654 | 1644 | N | Winter 2021/2022 |
| 1/22/2022 | 29777 | 541 | 1143 | 40 | 40 | 0 | 2800 | 4039 | 24622 | 20349 | 2305 | 22654 | 1968 | N | Winter 2021/2022 |
| 1/29/2022 | 29784 | 541 | 1135 | 40 | 339 | 0 | 3100 | 4039 | 24022 | 20121 | 2305 | 22426 | 1596 | N | Winter 2021/2022 |
| 2/5/2022 | 29784 | 541 | 1135 | 40 | 375 | 0 | 3100 | 3590 | 24435 | 19847 | 2305 | 22152 | 2283 | N | Winter 2021/2022 |
| 2/12/2022 | 29784 | 541 | 1135 | 40 | 330 | 0 | 3100 | 3291 | 24779 | 19817 | 2305 | 22122 | 2657 | N | Winter 2021/2022 |
| 2/19/2022 | 29784 | 541 | 1135 | 40 | 325 | 0 | 3100 | 2693 | 25382 | 19547 | 2305 | 21852 | 3530 | N | Winter 2021/2022 |
| 2/26/2022 | 29784 | 541 | 1135 | 40 | 380 | 0 | 3100 | 2244 | 25776 | 18533 | 2305 | 20838 | 4938 | N | Winter 2021/2022 |
| 3/5/2022 | 29784 | 541 | 1135 | 40 | 438 | 270 | 2200 | 1824 | 26768 | 18174 | 2305 | 20479 | 6289 | N | Winter 2021/2022 |
| 3/12/2022 | 29784 | 541 | 1135 | 40 | 738 | 718 | 2200 | 778 | 27066 | 17973 | 2305 | 20278 | 6788 | N | Winter 2021/2022 |
| 3/19/2022 | 29784 | 541 | 1135 | 40 | 1252 | 963 | 2200 | 84 | 27001 | 17598 | 2305 | 19903 | 7098 | N | Winter 2021/2022 |
| 3/26/2022 | 29760 | 540 | 1135 | 40 | 1713 | 757 | 2700 | 0 | 26305 | 17017 | 2305 | 19322 | 6983 | 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).
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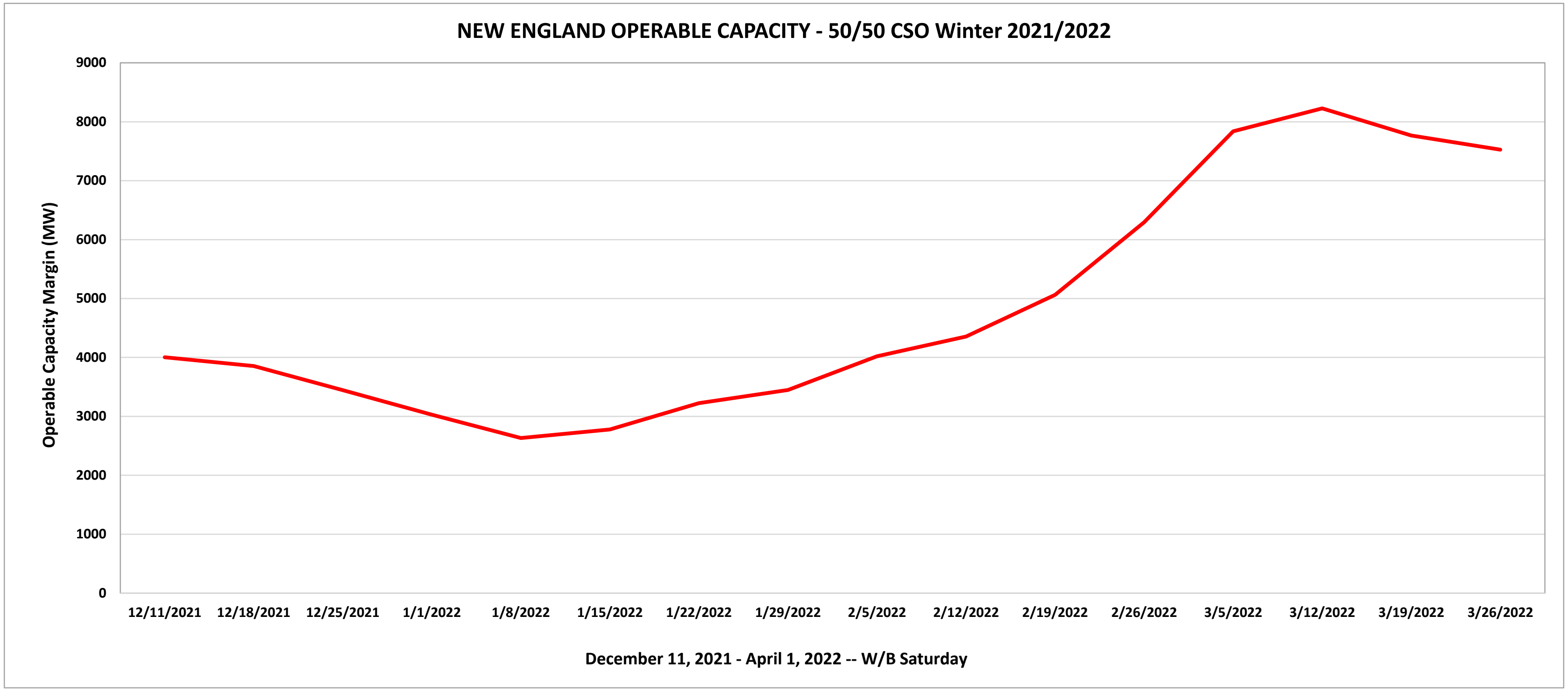
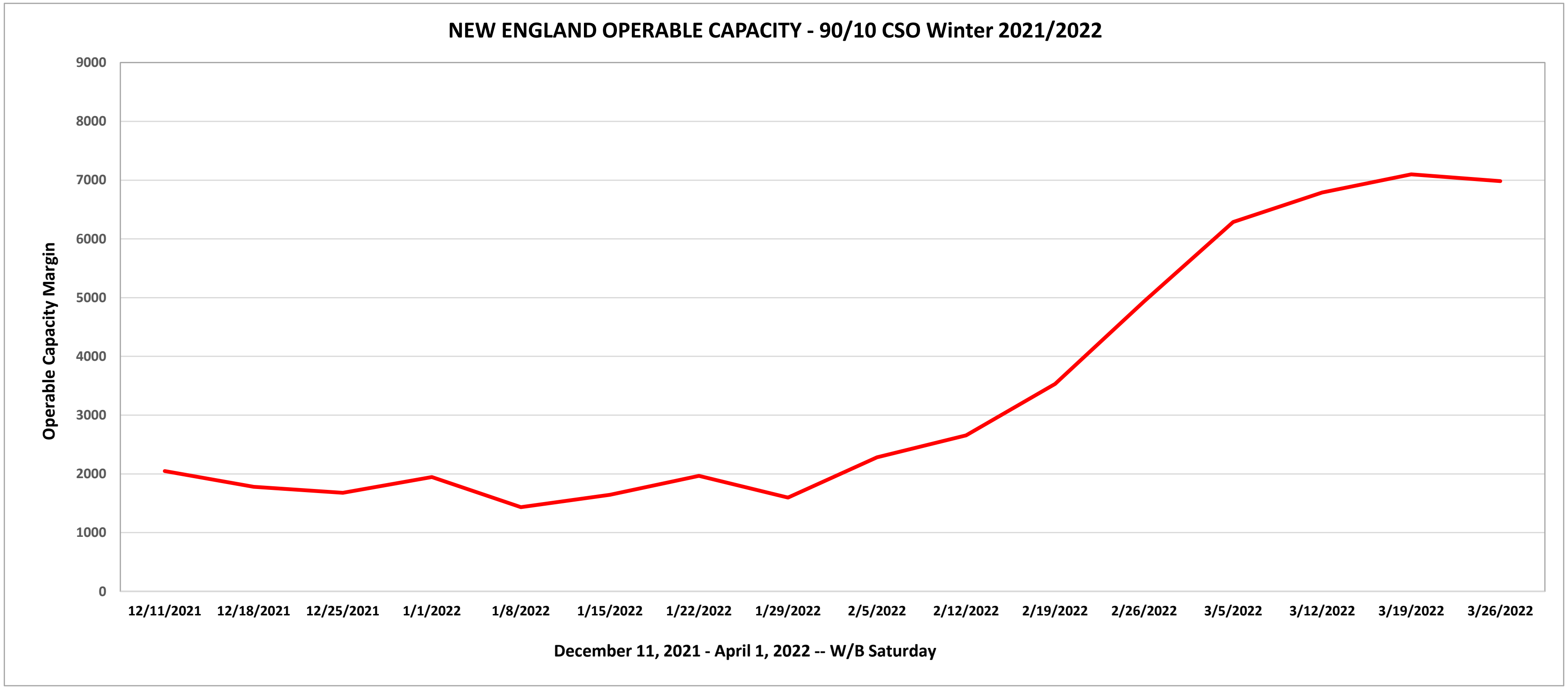
**13. CSO Operable Capacity Margin MW:** CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
**14. Operable Capacity Season Label:** Applicable season and year.
**15. Season Minimum Operable Capacity Flag:** this column indicates whether or not a week has the lowest capacity margin for its applicable season.

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

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



# 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<br>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.<br>Begin to allow the depletion of 30-minute reserve. | 0 [1]<br>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<br>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.<br><br>Voluntary Load Curtailment by Large Industrial and Commercial Customers. | 5<br><br>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

# MEMORANDUM

**TO:** NEPOOL Participants Committee

**FROM:** Eric Runge, NEPOOL Counsel

**DATE:** November 23, 2021

**RE:** Vote on Tariff Changes that Add a Process for the Conduct of Longer-Term Transmission Studies

---

At the December 2, 2021 meeting of the Participants Committee you will be asked to vote on revisions to ISO-NE Tariff Sections I (Definitions) and II (Open Access Transmission Tariff ("OATT"), Attachment K) to authorize ISO-NE to conduct transmission planning studies in response to requests from NESCOE for such studies ("Transmission Planning Revisions").[1] The proposal is part of a larger process to "implement a state-led, proactive scenario-based planning process for longer term analysis of state mandates and policies as a routine planning practice." For detail on this proposal, please see the Tariff revisions and related background materials that have been included with this memorandum.

The Transmission Committee considered the Transmission Planning Revisions over three meetings. At its November 19 meeting last Friday, the Transmission Committee unanimously recommended Participants Committee support for the proposal, with no opposition and three abstentions from the Supplier Sector noted.

The following resolution can be used for Participants Committee action:

> *Resolved*, that the Participants Committee supports the Transmission Planning Revisions to Sections I and II of the ISO-NE Tariff as recommended by the Transmission Committee and as distributed to the Participants Committee for its December 2, 2021 meeting, together with any changes agreed to at the meeting, and any non-substantive changes agreed to by the Chair and Vice-Chair of the Transmission Committee after the meeting.[2]

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[1] The Transmission Planning Revisions proposal was initiated by a request from the New England States in their "Vision for a Clean, Affordable and Reliable 21st Century Regional Electric Grid" ("Vision Statement"). The Vision Statement is available here: https://nescoe.com/resource-center/vision-stmt-oct2020/.

[2] An ISO-NE presentation containing the revisions and background material is also available here: https://www.iso-ne.com/static-assets/documents/2021/11/a03_tc_2021_11_19_extended_term_planning.pdf

memo

**To:** NEPOOL Transmission Committee

**From:** Brent Oberlin, Director, Transmission Planning

**Date:** November 18, 2021

**Subject:** Attachment K Revisions: Extended-Term Transmission Planning

The ISO is requesting a vote on the Attachment K Revisions: Extended-term Transmission Planning proposal. In response to the New England States' Vision for a Clean, Affordable, and Reliable 21st Century Regional Electric Grid, this proposal will address the rules in Attachment K of the Open Access Transmission Tariff (OATT) to incorporate a new transmission planning process primarily focused beyond the current ten-year planning horizon. A new section 16 is added to Attachment K of the OATT to establish the procedures and process for conducting Longer-Term Transmission Studies, and corresponding conforming changes, grammar, and clarifying updates made elsewhere in Attachment K. Additional revisions include corresponding new definitions added to Section I.2.2 of the Tariff.

The proposal for the committee's consideration at its November 19th meeting has been presented in the meeting dates outlined below:

- September 28, agenda item #7 https://www.iso-ne.com/event-details?eventId=144088
- October 26, agenda item #3 https://www.iso-ne.com/event-details?eventId=144089
- November 19, agenda item #3 https://www.iso-ne.com/event-details?eventId=144090

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

## ATTACHMENT K REVISIONS: EXTENDED-TERM PLANNING
## DRAFT TARIFF REDLINES

### DEFINED TERMS TO BE ADDED IN SECTION I.2.2 OF THE TARIFF

**Longer-Term Transmission Study** is a study conducted by the ISO pursuant to the process set out in Section 16 of Attachment K of the OATT. The 2050 Transmission Study shall be the first Longer-Term Transmission Study.[A1]

**State-identified Requirement** refers to a legal requirement, mandate or policy of a New England state or local government that forms the basis for a Longer-Term Transmission Study request submitted to the ISO pursuant to the process set out in Section 16 of Attachment K of the OATT.

# ATTACHMENT K REVISIONS: EXTENDED-TERM PLANNING

# DRAFT TARIFF REDLINES – ATTACHMENT K

## ATTACHMENT K
## REGIONAL SYSTEM PLANNING PROCESS

## TABLE OF CONTENTS[A1]

### 2.2 Role of Planning Advisory Committee

The Planning Advisory Committee may provide input and feedback to the ISO concerning the regional system planning process, including the development of and review of Needs Assessments, the conduct of Solutions Studies, the development of the RSP, and updates to the RSP Project List. Specifically, the Planning Advisory Committee serves to review and provide input and comment on: (i) the development of the RSP, (ii) assumptions for studies, (iii) the results of Needs Assessments, Solutions Studies, and competitive solutions developed pursuant to Section 4.3 of this Attachment, (iv) potential market responses to the needs identified by the ISO in a Needs Assessment or the RSP, ~~and~~ (v) Cluster Enabling Transmission Upgrades Regional Planning Studies, and (vi) Longer-Term Transmission Studies. The Planning Advisory Committee, with the assistance of and in coordination with the ISO, serves also to identify and prioritize requests for Economic Studies to be performed by the ISO, and provides input and feedback to the ISO concerning the conduct of Economic Studies and Public Policy Transmission Studies, including the criteria and assumptions for such studies. Based on input and feedback related to the regional system planning process provided by the Planning Advisory Committee to the ISO, the ISO shall consult with the appropriate NEPOOL technical committees, including but not limited to, the Markets, Reliability and Transmission Committees, on issues and concerns identified by the Planning Advisory Committee as requiring further investigation and consideration of potential changes to ISO New England Operating Documents.

### 2.3 Membership

There are no membership requirements to become part of the Planning Advisory Committee. Meetings are open to members of any entity, including State regulators or agencies and NESCOE, subject to the Critical Energy Infrastructure Information ("CEII") policy as further described in Section 2.4(d) of this Attachment. To be added to the Planning Advisory Committee email distribution list, an email address shall be provided to the Secretary of the Committee. Throughout this Attachment K, a member of the Planning Advisory Committee refers to any individual, whether they attend Planning Advisory Committee meetings or are included on the email distribution list.

### 2.4 Procedures

#### (a) Notice of Meetings

Prior to the beginning of each year, the ISO shall list on the ISO Calendar, which is available on the ISO's website, the proposed meeting dates for the Planning Advisory Committee for each date on which it has a completed application on file with the ISO whether it has met all of these criteria. A PTO determined by the ISO to meet all of these criteria will be deemed a Qualified Transmission Project Sponsor. A non-PTO entity determined by the ISO to meet all of these criteria will, upon its execution of the Non-incumbent Transmission Developer Operating Agreement (in the form specified in Attachment O of the OATT) and the Market Participant Service Agreement, be deemed a Qualified Transmission Project Sponsor.

**4B.4 List of Qualified Transmission Project Sponsors**

Qualified Transmission Project Sponsors are listed in Appendix 3 of this Attachment K.

**4B.5 Annual Certification**

Each Qualified Transmission Project Sponsor shall submit to the ISO annually a certification that the information initially submitted in response to Section 4B.2 of this Attachment K has not changed adversely in a material fashion, or (if a material adverse change has occurred in the intervening year) submit instead a new application for qualification as a project sponsor. In the latter case, the entity shall not be a Qualified Transmission Project Sponsor unless and until the ISO approves its new application.

## 5. Supply of Information and Data Required for Regional System Planning

The Transmission Owners, Generator Owners, Transmission Customers, Market Participants and other entities requesting transmission or interconnection service or proposing the integration of facilities to PTF in the New England Transmission System or alternatives to such facilities, and stakeholders requesting a Needs Assessment pursuant to Section 4.1 of this Attachment, shall supply, as required by the Tariff, the Participants Agreement, MPSAs, applicable transmission operating agreements, and/or other existing agreements, protocols and procedures, or upon request by the ISO, and subject to required CEII and confidentiality protections as specified in Section 2.4 of this Attachment, any information (including cost estimates) and data that is reasonably required to prepare an RSP~~,~~ or ~~or to~~[A2] perform a Needs Assessment, ~~or~~ Solutions Study, or any other study performed under this Attachment K.

## 6. Regional, Local and Interregional Coordination

### 6.1 Regional Coordination

The ISO shall conduct the regional system planning process for the PTF in coordination with the transmission-owning entities in, or other entities interconnected to, the New England Transmission System consistent with the accordance with Section 4.2.3 of Schedule 22, Section 1.5.3.3 of Schedule 23, and Section 4.2.3 of Schedule 25 of Section II of the Tariff.

**16. Procedures for the Conduct of Longer-Term Transmission Studies**

This Section 16 sets forth the procedures for the ISO's conduct of Longer-Term Transmission Studies. Other than Section 2, regarding the responsibilities of the Planning Advisory Committee, ~~and~~[A3] Section 5, regarding the supply of information, a[A4]nd this Section 16 of this Attachment K ~~and this Section 16~~, none of the other provisions in this Attachment K apply to the conduct of the Longer-Term Transmission Studies. These procedures supplement, and are not intended to replace, other study processes provided in this Attachment K.

**16.1 Request for Longer-Term Transmission Studies**

NESCOE~~, on behalf of one or more state governors or regulatory authorities,~~[A5] may submit a request for the ISO to conduct a Longer-Term Transmission Study to identify high-level concepts of transmission infrastructure and, if requested, high-level cost estimates that could meet State-identified Requirements specified in the request based on state-identified scenarios and timeframes, which may extend beyond the five-to-ten year planning horizon. A[A6] request for a Longer-Term Transmission Study may be submitted to the ISO no earlier than 6 months from conclusion of the prior study. The Longer-Term Transmission Study request shall identify the State-identified Requirements that serve as the basis of the request; the proposed objectives of the study; and the scenarios and timeframe(s) proposed for use ~~to be used~~ in the study.

~~A~~[A7] ~~request for a Longer-Term Transmission Study may be submitted to the ISO no more frequently than every three years from the date of the previous submittal, if the final study report associated with the prior study request has been issued.~~ ~~T~~[A8]~~he 2050 Transmission Study shall be the first Longer-Term Transmission Study.~~ ~~T~~[A9]~~he next request subsequent to the 2050 Transmission Study may be submitted after the later of October 16, 2023, or publication of the 2050 Transmission Study final report.~~

**16.2 Preparation for Conduct of the Longer-Term Transmission Studies; Stakeholder Input**

Upon receipt of a request for a Longer-Term Transmission Study from NESCOE, the ISO will post the request on the ISO's website. A meeting of the Planning Advisory Committee will be held promptly thereafter for NESCOE to present the Longer-Term Transmission Study request. NESCOE will then provide the ISO written confirmation of the specific scenarios to be analyzed in the study, together with the specific information to facilitate the conduct of the study, including, but not limited to: assumptions, types and location of new resource development, location of new loads and load serving stations, and injection points or geographic zones. The ISO will then develop a scope of work that may be performed, and post on the ISO's website the Longer-Term Transmission Study's proposed scope of work, associated parameters, and assumptions. A meeting of the Planning Advisory Committee will be held promptly thereafter in order to solicit stakeholder input on the study's scope, parameters, and assumptions. Members of the Planning Advisory Committee shall direct all such input related to the Longer-Term Transmission Study's scope, parameters, and assumptions to the ISO for consideration by the ISO and NESCOE, as applicable. Depending on the scope and objectives of a Longer-Term Transmission Study request, the ISO may request information~~, s~~[A10]~~uch as a longer-term plan for the distribution system,~~ to support consideration of new loads in the study. The ISO will provide the final scope of work for the Longer-Term Transmission Study to NESCOE for confirmation, and once written confirmation is received, will post the final scope of work on the ISO's website.

**16.3 Conduct of the Longer-Term Transmission Study; Stakeholder Input**

The ISO, in consultation with NESCOE, will perform the Longer-Term Transmission Study, supplemented by third-party consultants as necessary. The ISO may ask Participating Transmission Owners or Planning Advisory Committee members with special expertise to provide technical support or assist in the performance of the study. The study will consist of transmission system analysis~~; s~~[A11]~~uch as, steady-state thermal and voltage, stability, and short circuit,~~ to be performed under the conditions specified in the confirmed scope of work. If the ISO identifies a need to deviate from the final scope of work, the ISO will consult with NESCOE prior to incorporating the change. Once NESCOE provides written confirmation, the ISO will notify the Planning Advisory Committee of any changes. The study will assess the ability of the PTF to meet applicable planning criteria under the provided conditions.

The costs of the performance of the Longer-Term Transmission Study will be recovered pursuant to Schedule 1 of Section IV.A of the Tariff.

The ISO will post on the ISO's website the results of the Longer-Term Transmission Study. A meeting of the Planning Advisory Committee will be held promptly thereafter in order to solicit input on the study results. Members of the Planning Advisory Committee shall direct all such input related to the Longer-Term Transmission Study results to the ISO for consideration by the ISO and NESCOE, as applicable.

The ISO, in consultation with NESCOE, will prepare a Longer-Term Study report. The report will identify the overview of transmission system limitations and the high-level concepts of transmission infrastructure and, if requested, associated cost estimates, required to[A12] solve the longer-term issues identified in the study based on the state-identified scenarios and timeframe.

# Attachment K Revisions: Extended-Term Planning

*Third Meeting*

Brent Oberlin

(413) 540-4512 | BOBERLIN@ISO-NE.COM

# Project Title: Attachment K Extended-Term Planning

**Proposed Effective Date:** February 2022

- In the New England States' Vision for a Clean, Affordable, and Reliable 21st Century Regional Electric Grid (Vision Statement), the New England states identified a need for changes in transmission system planning to advance the vision of a clean, affordable and reliable regional electric grid
  - "As a region, we cannot effectively plan for integrating clean energy resources and decarbonization of the electricity system required by certain states' laws without having a clear understanding of the investments needed in regional transmission infrastructure."
- The Vision Statement, thus, recommended that ISO identify process changes to allow for a routine transmission planning process to help "inform all stakeholders of the amount and type of transmission infrastructure needed to cost-effectively integrate clean energy resources" and enumerated certain criteria for that framework

# Background and Purpose

- NESCOE's June 21 Governor's Report recommended the revisions to the ISO Tariff to "implement a state-led, proactive scenario-based planning process for longer-term analysis of state mandates and policies as a routine planning practice"
- The ISO is proposing to revise Attachment K of the ISO New England Open Access Transmission Tariff (OATT) to incorporate a new transmission planning process primarily focused beyond the current ten-year planning horizon
  - Multi-phased effort, with the first phase establishing the rules to enable the New England states to request that the ISO perform scenario-based transmission planning studies, on a routine basis
- This is the third meeting at the Transmission Committee to discuss these changes, which are anticipated to be filed with FERC by the end of this year

# Background and Purpose, cont.

- Today's discussion is focused on the first phase of the effort, enabling the ISO's continued performance of state-requested transmission analysis to meet the state-identified requirements
  - The second phase of the effort will address the rules to enable a state or states to consider potential options for addressing the identified issues and cost allocation for associated transmission improvements
    - The second phase will begin in early 2022, with a filing expected later that year

# Problem Statement

- Attachment K of the OATT describes the process, and corresponding assumptions, for the performance of needs assessments and solution development for reliability, market efficiency and public policy based needs within the ten-year planning horizon
- The current processes do not support the performance of state-requested transmission analysis based on state-developed scenarios, inputs and assumptions, nor do they support transmission analysis beyond the ten-year horizon
- Creation of a new process in Attachment K would support the ISO's performance of state-requested transmission analysis, including development of high-level transmission concepts, along with cost estimates if requested, to meet the state-identified requirements

# PROPOSED TARIFF CHANGES SINCE THE OCTOBER TRANSMISSION COMMITTEE MEETING

# Overview of Tariff Changes Made Since the October TC meeting

- Based on TC feedback and additional ISO review of the proposed changes to Attachment K, modifications have been made in the following areas
  - Grammar corrections
    - Sections 5, 16, and 16.3 of Attachment K
  - Removing an unnecessary and incorrect description of NESCOE's role
    - Section 16.1 of Attachment K
  - Addressing concerns related to when subsequent studies may be initiated
    - Section 16.1 of Attachment K and 1.2.2 of the Tariff
  - Removing unnecessary language that provided an example of information that may be requested by the ISO to support performance of the study
    - Section 16.2 of Attachment K
  - Removing unnecessary language that provided examples of various issues that a transmission study may review
    - Section 16.3 of Attachment K

# Proposed Tariff Changes: Tariff Section I.2.2

| Tariff Section | Tariff Change | Reason for Change in Yellow |
|---|---|---|
| Section I.2.2 | **Longer-Term Transmission Study** is a study conducted by the ISO pursuant to the process set out in Section 16 of Attachment K of the OATT. The 2050 Transmission Study shall be the first Longer-Term Transmission Study.<br><br>**State-identified Requirement** refers to a legal requirement, mandate or policy of a New England state or local government that forms the basis for a Longer-Term Transmission Study request submitted to the ISO pursuant to the process set out in Section 16 of Attachment K of the OATT. | Language moved to the definition as a result of the changes to Section 16.1. |

# Proposed Tariff Changes: Attachment K

| Tariff Section | Tariff Change | Reason for Change in Yellow |
|---|---|---|
| Attachment K, Section 5 | **5. Supply of Information and Data Required for Regional System Planning**<br>The Transmission Owners, Generator Owners, Transmission Customers, Market Participants and other entities requesting transmission or interconnection service or proposing the integration of facilities to PTF in the New England Transmission System or alternatives to such facilities, and stakeholders requesting a Needs Assessment pursuant to Section 4.1 of this Attachment, shall supply, as required by the Tariff, the Participants Agreement, MPSAs, applicable transmission operating agreements, and/or other existing agreements, protocols and procedures, or upon request by the ISO, and subject to required CEII and confidentiality protections as specified in Section 2.4 of this Attachment, any information (including cost estimates) and data that is reasonably required to prepare an RSP, or ~~or to~~ perform a Needs Assessment, ~~or~~ Solutions Study, or any other study performed under this Attachment K. | Reinstating the word “or” to correct the grammar. |

# Proposed Tariff Changes: Attachment K

| Tariff Section | Tariff Change | Reason for Change in Yellow |
|---|---|---|
| Attachment K, new Section 16 | **16. Procedures for the Conduct of Longer-Term Transmission Studies**<br>This Section 16 sets forth the procedures for the ISO's conduct of Longer-Term Transmission Studies. Other than Section 2, regarding the responsibilities of the Planning Advisory Committee, ~~and~~ Section 5, regarding the supply of information, and this Section 16 of this Attachment K ~~and this Section 16~~, none of the other provisions in this Attachment K apply to the conduct of the Longer-Term Transmission Studies. These procedures supplement, and are not intended to replace, other study processes provided in this Attachment K. | Deleted an extra "and" and moved "Section 16" before "of this Attachment K" to correct grammar. |

# Proposed Tariff Changes: Attachment K

| Tariff Section | Tariff Change | Reason for Change in Yellow |
|---|---|---|
| Attachment K, new Section 16.1 | **16.1 Request for Longer-Term Transmission Studies**<br>NESCOE~~, on behalf of one or more state governors or regulatory authorities,~~ may submit a request for the ISO to conduct a Longer-Term Transmission Study to identify high-level concepts of transmission infrastructure and, if requested, high-level cost estimates that could meet State-identified Requirements specified in the request based on state-identified scenarios and timeframes, which may extend beyond the five-to-ten year planning horizon. A request for a Longer-Term Transmission Study may be submitted to the ISO no earlier than 6 months from conclusion of the prior study. The Longer-Term Transmission Study request shall identify the State-identified Requirements that serve as the basis of the request; the proposed objectives of the study; and the scenarios and timeframe(s) proposed for use ~~to be used~~ in the study.<br><br>~~A request for a Longer-Term Transmission Study may be submitted to the ISO no more frequently than every three years from the date of the previous submittal, if the final study report associated with the prior study request has been issued. The 2050 Transmission Study shall be the first Longer-Term Transmission Study. The next request subsequent to the 2050 Transmission Study may be submitted after the later of October 16, 2023, or publication of the 2050 Transmission Study final report.~~ | NESCOE serves in a coordinating role for the states. This language has been removed as it is unnecessary and it doesn't accurately describe NESCOE's structure. Addressing concerns related to the specificity as to when a study is completed and the proposed study cycle. Language was also modified since the request is a proposal at this time. |

# Proposed Tariff Changes: Attachment K

| Tariff Section | Tariff Change | Reason for Change in Yellow |
|---|---|---|
| Attachment K, new Section 16.2 | **16.2 Preparation for Conduct of the Longer-Term Transmission Studies; Stakeholder Input**<br>Upon receipt of a request for a Longer-Term Transmission Study from NESCOE, the ISO will post the request on the ISO's website. A meeting of the Planning Advisory Committee will be held promptly thereafter for NESCOE to present the Longer-Term Transmission Study request. NESCOE will then provide the ISO written confirmation of the specific scenarios to be analyzed in the study, together with the specific information to facilitate the conduct of the study, including, but not limited to: assumptions, types and location of new resource development, location of new loads and load serving stations, and injection points or geographic zones. The ISO will then develop a scope of work that may be performed, and post on the ISO's website the Longer-Term Transmission Study's proposed scope of work, associated parameters, and assumptions. A meeting of the Planning Advisory Committee will be held promptly thereafter in order to solicit stakeholder input on the study's scope, parameters, and assumptions. Members of the Planning Advisory Committee shall direct all such input related to the Longer-Term Transmission Study's scope, parameters, and assumptions to the ISO for consideration by the ISO and NESCOE, as applicable. Depending on the scope and objectives of a Longer-Term Transmission Study request, the ISO may request information~~, such as a longer-term plan for the distribution system,~~ to support consideration of new loads in the study. The ISO will provide the final scope of work for the Longer-Term Transmission Study to NESCOE for confirmation, and once written confirmation is received, will post the final scope of work on the ISO's website. | Unnecessary language deleted. This language can be reviewed through modifications to the Transmission Planning Process Guide. |

# Proposed Tariff Changes: Attachment K

| Tariff Section | Tariff Change | Reason for Change in Yellow |
|---|---|---|
| Attachment K, new Section 16.3 | **16.3 Conduct of the Longer-Term Transmission Study; Stakeholder Input**<br><br>The ISO, in consultation with NESCOE, will perform the Longer-Term Transmission Study, supplemented by third-party consultants as necessary. The ISO may ask Participating Transmission Owners or Planning Advisory Committee members with special expertise to provide technical support or assist in the performance of the study. The study will consist of transmission system analysis~~; such as, steady-state thermal and voltage, stability, and short circuit,~~ to be performed under the conditions specified in the confirmed scope of work. If the ISO identifies a need to deviate from the final scope of work, the ISO will consult with NESCOE prior to incorporating the change. Once NESCOE provides written confirmation, the ISO will notify the Planning Advisory Committee of any changes. The study will assess the ability of the PTF to meet applicable planning criteria under the provided conditions.<br><br>The costs of the performance of the Longer-Term Transmission Study will be recovered pursuant to Schedule 1 of Section IV.A of the Tariff.<br><br>The ISO will post on the ISO's website the results of the Longer-Term Transmission Study. A meeting of the Planning Advisory Committee will be held promptly thereafter in order to solicit input on the study results. Members of the Planning Advisory Committee shall direct all such input related to the Longer-Term Transmission Study results to the ISO for consideration by the ISO and NESCOE, as applicable.<br><br>The ISO, in consultation with NESCOE, will prepare a Longer-Term Study report. The report will identify the overview of transmission system limitations and the high-level concepts of transmission infrastructure and, if requested, associated cost estimates, required to solve the longer-term issues identified in the study based on the state-identified scenarios and timeframe. | Unnecessary language deleted. This language can be reviewed through modifications to the Transmission Planning Process Guide. |

# ADDITIONAL DISCUSSION FROM THE OCTOBER TRANSMISSION COMMITTEE MEETING

# October TC Discussion

- At the October TC meeting, a question was raised regarding the allocation of costs as described in Schedule 1 of Section IV.A of the Tariff
- Costs are allocated to Regional Network Service and Through or Out Service customers
  - Split between the two is shown in the upper right and can be found at https://www.iso-ne.com/static-assets/documents/2019/12/section-4a-rate-summary_2021.xls
- The ISO had previously reviewed the split of Schedule 1 across NEPOOL sectors. The review showed that there is little change from year to year. The values in the lower right are from 2018

| [1-2] See 'Notes' at end of table | | Schedule 1 Scheduling, System Control and Dispatch Service | |
|---|---|---|---|
| | | Regional Network Service (RNS) | Through or Out Service (TOUT) |
| Year | Effective Date | $/kW-month | $/kWh[1] |
| 2013 | Jan 1 | 0.16545 | 0.00023 |
| 2014 | Jan 1 | 0.15640 | 0.00021 |
| 2015 | Jan 1 | 0.15570 | 0.00021 |
| 2016 | Jan 1 | 0.19275 | 0.00026 |
| 2017 | Jan 1 | 0.19093 | 0.00026 |
| 2018 | Jan 1 | 0.17886 | 0.00025 |
| 2019 | Jan 1 | 0.17285 | 0.00024 |
| 2020 | Jan 1 | 0.17626 | 0.00024 |
| 2021 | Jan 1 | 0.19383 | 0.00027 |

| Sector | Percentage |
|---|---|
| Transmission | 87.4 |
| Publicly Owned | 10.1 |
| Supplier | 2.4 |
| Generation | 0.2 |
| Alternative Resources | 0.0 |
| Other | 0.0 |

# October TC Discussion, cont.

At the October TC meeting, the ISO was asked to provide the differences between a transmission study and an economic study

| | Longer-Term Transmission Study | Economic Study |
|---|---|---|
| **Governed by…** | Attachment K, Section 16 | Attachment K, Section 4.1(b) |
| **Requested by…** | NESCOE | Any stakeholder (most past studies have been requested by stakeholders other than NESCOE) |
| **Focus on…** | Analyzing the performance of the transmission system based on detailed transmission models | Evaluating various metrics using a high-level time-series model of transmission system (typically ignores individual element constraints) |
| **Sample types of analysis** | Thermal, voltage, short-circuit, transient stability | Production cost, resource curtailment, emissions, interface congestion, unserved energy |
| **Focus of cost analysis** | Cost of transmission system additions and modifications | Production cost, transmission interface congestion costs, locational marginal prices |
| **Ongoing studies** | 2050 Transmission Study requested by NESCOE (scope discussed at the November Planning Advisory Committee meeting) | 2021 Economic Study requested by NEPOOL: Future Grid Reliability Study (FGRS), Phase I |

# Conclusion

- The ISO is proposing additions to Attachment K to support periodic studies that address state requests as provided by NESCOE
- Modifications have been made to address stakeholder concerns raised at the October TC meeting to remove unnecessary language and to address concerns related to the timing of subsequent studies

# Stakeholder Schedule

## *Proposed Effective Date – February 2022*

| Stakeholder Committee and Date | Scheduled Project Milestone |
|---|---|
| **September 28, 2021** | Discussion of concepts to be included in upcoming Attachment K revisions |
| **October 26, 2021** | Respond to stakeholder questions from previous meeting and initial review of proposed redlines |
| **November 19, 2021** | Respond to stakeholder questions from previous meeting, review of proposed redlines, and vote on the proposed Attachment K revisions |
| **Participants Committee December 2, 2021** | Vote |

# Questions

Brent Oberlin

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ISO new england

memo

**To:** NEPOOL Participants Committee

**From:** Jay Dwyer, Secretary, NEPOOL Transmission Committee

**Date:** November 19, 2021

**Subject:** Actions of the Transmission Committee

This memo is notification to the Participants Committee of the following actions taken by the Transmission Committee at its November 19, 2021 meeting. All sectors had a quorum.

**Agenda Item No. 2. September 28, 2021 Meeting Minutes**

**ACTION: APPROVED**

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

> *Resolved*, that the Transmission Committee approves the minutes of the October 26, 2021 meeting as reflected in the materials distributed for its November 19, 2021 meeting, with any changes agreed to at the meeting and such further non-substantive changes as the Chair and Vice-Chair approve.

The motion was then voted. The motion passed based on a voice vote, with no opposition and no abstentions recorded.

**Agenda Item No. 3: Proposed Revisions to Attachment K to Provide a Framework for Extended-Term Transmission Planning Studies**

**ACTION: APPROVED**

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

> *Resolved*, that the Transmission Committee recommends that the Participants Committee support the proposed revisions to Attachment K of Section II of the Tariff to revise Attachment K of Section II of the ISO New England Inc. Transmission, Markets and Services Tariff to provide for longer term (more than ten years) Transmission Studies as distributed for the Transmission Committee's November 19, 2021 meeting with such changes as are agreed to at that meeting and such further non-substantive changes as the Chair and Vice Chair approve.

The motion was voted and, based on a voice vote, passed with no opposition and three abstentions recorded in the Supplier Sector.

# NEW ENGLAND POWER POOL
# PARTICIPANTS COMMITTEE MEETING

## December 2, 2021

## RESOLUTION REGARDING ELECTION OF OFFICERS FOR 2022

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

WHEREAS, pursuant to those procedures the individuals indentified in the following resolution were nominated and elected for 2022 to the offices of Chair and Vice-Chair, as set forth opposite their names; and

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

NOW, THEREFORE, IT IS

RESOLVED, that the Participants Committee hereby adopts and ratifies the results of the election held in accordance with Section 4.6 of the Bylaws and elects the following individuals for 2022 to the offices set forth opposite their names to serve until their successors are elected and qualified:

| | |
|---|---|
| Chair | David A. Cavanaugh |
| Vice-Chair | Christina H. Belew |
| Vice-Chair | Sarah Bresolin |
| Vice-Chair | Francis J. Ettori, Jr. |
| Vice-Chair | Michelle C. Gardner |
| Vice-Chair | Aleksander Mitreski |
| Secretary | David T. Doot |
| Assistant Secretary | Sebastian M. Lombardi |

# M E M O R A N D U M

**TO:** NEPOOL Participants Committee Members and Alternates

**FROM:** Tom Kaslow, Chair, NEPOOL Budget & Finance Subcommittee
Paul Belval, NEPOOL Counsel

**DATE:** November 23, 2021

**RE:** Estimated Budget for 2022 Participant Expenses

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The Participants Committee will be asked at its December 2 meeting to approve the estimated NEPOOL expense budget for 2022, which is attached to this memorandum (the "2022 Budget"). As in prior years, the proposed 2022 Budget estimates are compared to both the current-year estimated expenses approved by the Participants Committee at its last annual meeting and the current forecast of actual expenses for this year (Attachment A). Also as in prior years, an estimated calculation of the per-Participant share of the 2022 Budget expenses are compared to per-Participant shares of expenses five years ago (Attachment B). Impacted by the number of members over which expenses are allocated, 2022 per-Participant expenses are projected, when compared to 2017 numbers, to generally decrease (by 3.1% for most Participants (Generation, Supplier and Large AR Providers), by 2.2% for Publicly Owned Entities, but to increase 5.5% for the voting Transmission Owners).

Consistent with the practice in previous years, the NEPOOL Budget & Finance Subcommittee (the "Subcommittee") has worked with NEPOOL Counsel, the GIS Administrator, the ISO and NEPOOL's Independent Financial Advisor to develop the 2022 Budget. The Subcommittee will discuss the proposed 2022 Budget at its November 29 meeting, and we will report the results of that discussion at the December 2 Participants Committee meeting.

The following form of resolution may be used in acting on the 2022 Budget:

RESOLVED, that the Participants Committee adopts the estimated NEPOOL expense budget for 2022 as presented at this meeting.

## ESTIMATED 2022 NEPOOL BUDGET COMPARED TO 2021 NEPOOL BUDGET AND 2021 PROJECTED ACTUAL EXPENSES

| Line Items | 2021 Approved Budget | 2022 Proposed Budget | 2021 Current Forecast |
|---|---|---|---|
| NEPOOL Counsel Fees (1) | $4,100,000 | $4,200,000 | $4,100,000 |
| NEPOOL Counsel Disbursements (1) | $ 20,000 | $ 30,000 | $ 35,000 |
| Independent Financial Advisor Fees and Disbursements (2) | $ 45,000 | $ 45,000 | $ 45,000 |
| Committee Meeting Expenses (3)(4) | $ 510,000 | $ 725,000 | $ 75,000 |
| Generation Information System (5) | $ 1,070,600 | $ 950,000 | $ 1,070,600 |
| Credit Insurance Premium (3) | $ 475,000 | $ 637,000 | $ 649,000 |
| NEPOOL Audit Management Subcommittee ("NAMS") Consultant (6) | $ 0 | $ 0 | $ 0 |
| SUBTOTAL EXPENSES | $6,220,600 | $6,587,000 | $5,974,600 |
| **Revenue** | | | |
| NEPOOL Membership Fees (3) (7) | ($2,110,000) | ($2,140,000) | ($2,110,000) |
| Generation Information System (5) (8) | ($1,070,600) | ($ 950,000) | ($1,070,600) |
| Credit Insurance Premium (3) (9) | ($ 475,000) | ($ 637,000) | ($ 649,000) |
| TOTAL REVENUE | ($3,655,600) | ($3,727,000) | ($3,829,600) |
| **TOTAL NEPOOL EXPENSES** | **$2,565,000** | **$2,860,000** | **$2,145,000** |

Notes

(1) 2022 proposed estimate provided by Day Pitney LLP, NEPOOL counsel.

(2) 2022 proposed estimate provided by Michael M. Mackles, NEPOOL's Independent Financial Advisor.

(3) 2022 proposed estimate provided by ISO New England Inc. ("ISO").

(4) 2022 proposed estimate is based on 2019 actuals assuming resumption of in person meeting on a forward going basis in 2022.

(5) Based on fee arrangement in Extension of and First Amendment to Amended and Restated Generation Information System Administration Agreement, pursuant to which the fixed fee for 2022 is projected to be $950,000. Estimate assumes NEPOOL will not exceed 500 development hours for changes to GIS, and any additional development hours would impose additional charges on NEPOOL.

(6) If NEPOOL determines that an audit should be performed in 2022, funding for that audit will be addressed separately.

(7) The 2022 proposed estimate is based on the 2021 actual receipts through September 2021, plus a forecast for new members for the remainder of the year. The breakdown for the proposed budget is approximately: 400 members at $5,000 each, 25 members at $1,000 each, 17 members at $500 each, 30 members at $1,500 each, and 29 members of large end users and MPEU's. This estimate takes into account the terminations throughout the year.

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

(9) Credit insurance premium is paid by Qualifying Market Participants according to methodology described in Section IX of the ISO Financial Assurance Policy. The 2022 premium is based on 2021 annual policy sales, with projected escalation factors for 2022.

# ESTIMATED BREAKDOWN OF PROJECTED 2022 NEPOOL EXPENSE BUDGET AMONG SECTOR MEMBERS

**(2022 figures assume no change in current NEPOOL membership)**
**(2017 figures as projected and budgeted at 2016 Annual Meeting)**

| **CALCULATION OF COSTS TO BE ALLOCATED TO NEPOOL SECTORS** | | | |
|---|---|---|---|
| | | **2022** | **2017** |
| A. | Total Projected NEPOOL Expenses (not including costs associated with GIS, credit insurance premium, which are funded separately) | **5,000,000** | **4,619,000** |
| B. | Projected NEPOOL Membership Fees | **2,140,000** | **1,900,000** |
| C. | Total Projected NEPOOL Expenses to be Funded Through Non-Hourly Charges (A – B) | **2,860,000** | **2,719,000** |
| D. | Projected Amount to be paid by all Market Participant End Users (based on highest hourly load in any month in preceding calendar year) (figure used here for 2020 is based on 2018 peak loads of MPEU members) | **41,179** | **45,262** |
| E. | Total Amount paid by all Load Response, Distributed Generation, and Small Renewable Generation Resource Providers in AR Sector (figure used here for 2020 is estimated amount based on 2019 membership data) | **77,462** | **70,717** |
| F. | [Reserved] | **0** | **0** |
| G. | Large Renewable Generation Sub-Sector Share (C-(D+E)) x RG% | **274,136** | **271,900** |
| H. | Total Amount to be Allocated among Transmission, Generation, Supplier and Publicly Owned Entity Sectors (“Remaining Sectors”) (C – (D+E+G)) | **2,467,223** | **2,331,121** |

| **CALCULATION OF SECTOR ALLOCATIONS** | | | |
|---|---|---|---|
| | | **2022** | **2017** |
| I. | Amount to be allocated to each of the Remaining Sectors<br>(H ÷ 4) | **616,806** | **582,780** |
| J. | Total Amount paid by Related Person Suppliers (2 voting members)<br>$(I \div s_y) \times rps_y$ | **8,939** | **9,106** |
| K. | Aggregate Share to be paid by Generation Sector/Supplier Sector/ Large Renewable Generation Resource Providers<br>((I x 2) + G – J) | **1,498,808** | **1,428,355** |
| L. | [Reserved] | **0** | **0** |
| M. | Remainder of Aggregate Share to be paid, on a per member basis, by voting members in the Generation Sector, Supplier Sector (excluding Related Person Suppliers), and Large Renewable Generation Resource Providers<br>$(K \div (g_y + (s_y - rps_y) + lrg_y))$ | **9,486** | **9,783** |
| N. | Transmission Sector Share per full voting member<br>$(I \div t_y)$ | **123,361** | **116,556** |
| O. | [Reserved] | **0** | **0** |
| P. | Publicly Owned Entity Sector Member Share (assuming equal sharing of Publicly Owned Entity Sector Share Participant Expense among voting Sector members)[i]<br>$(I \div poe_y)$ | **10,454** | **10,224** |

| **ANNUAL VARIABLES** | | | |
|---|---|---|---|
| | | **2022** | **2017** |
| $s_y$ | # Supplier Sector voting members | **129** | **128** |
| $rps_y$ | # Supplier Sector Related Person Suppliers | **2** | **2** |
| $g_y$ | # Generation Sector voting members | **11** | **14** |
| $lrg_y$ | # AR Sector Large Renewable Generation Resource Providers | **11** | **6** |
| RG% | Lesser of ($lrg_y$*2%) or 10% | **10%** | **10%** |
| $t_y$ | # Transmission Sector voting members | **5** | **5** |
| $poe_y$ | # Publicly Owned Entity voting members | **59** | **57** |



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# EXECUTIVE SUMMARY
## Status Report of Current Regulatory and Legal Proceedings
## as of December 1, 2021

The following activity, as more fully described in the attached litigation report, has occurred since the report dated November 2, 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) | Nov 8 | ISO-NE answers *Sep 7 Order*, explaining why Schedule 25 and Tariff section I.3.10 remain just & reasonable; comment deadline ***Jan 7, 2022*** |
| | | | Nov 12, 19 | Vista, Pixelle Androscoggin intervene out-of-time |
| | 3 | Green Development DAF Charges Complaint Against National Grid (EL21-47) | Nov 26 | FERC issues a "Notice of Denial of Rehearing by Operation of Law and Providing for Further Consideration" of Green Development's request for rehearing of the *Green Development Complaint Order* |
| | 4 | NECEC/Avangrid Complaint Against NextEra/Seabrook (EL21-6) | Nov 9 | Avangrid answers NextEra Nov 4 pleading |
| | | | Nov 17 | NextEra moves to lodge NRC Seabrook Report |
| | | | Nov 29 | Avangrid opposes NextEra Nov 17 motion to lodge |
| | 5 | NextEra Energy Seabrook Declaratory Order Petition re: NECEC Elective Upgrade Costs Dispute (EL21-3) | Nov 17 | NextEra moves to lodge NRC Seabrook Report |
| | | | Nov 29 | Avangrid opposes NextEra Nov 17 motion to lodge |

## II. Rate, ICR, FCA, Cost Recovery Filings

| | | | | |
|---|---|---|---|---|
| * | 8 | ICR-Related Values and HQICCs – Annual Reconfiguration Auctions (ER22- ) | Nov 30 | ISO-NE and NEPOOL jointly file ICR-Related Values and HQICCs for the 2022/23 ARA3, 2023/24 ARA2; and 2024/25 ARA1; comment deadline ***Dec 21, 2021*** |
| * | 8 | FCA16 Qualification Informational Filing (ER22-391) | Nov 9 | ISO-NE submits required FCA16 informational filing |
| | | | Nov 16-Dec 1 | NEPOOL, Calpine, Dominion, ENE (out-of-time), Eversource, National Grid, NESCOE, NRG, MA DPU intervene |
| | | | Nov 24 | Borrego, Anbaric/MMWEC submit protests |
| * | 9 | ICR-Related Values and HQICCs – FCA16 (2025-26) Capacity Commitment Period (ER22-378) | Nov 9 | ISO-NE files ICR-Related Values for the 2025-26 Capacity Comm. Period |
| | | | Nov 10-24 | NEPOOL, Calpine, Dominion, Eversource, MA DPU, National Grid, NESCOE, NRG intervene |
| | | | Nov 12, 15 | Climate Code Blue, Greater Boston Physicians for Social Responsibility submit comments |
| | 8 | 2022 NESCOE Budget (ER22-117) | Nov 4-15 | Eversource, MA DPU (out-of-time), National Grid intervene |
| | | | Nov 5 | NEPOOL filed comments supporting the 2022 NESCOE Budget |
| | 9 | 2022 ISO-NE Administrative Costs and Capital Budgets (ER22-113) | Nov 4-5 | National Grid, Eversource intervene |

| | | | | |
|---|---|---|---|---|
| | 11 | Mystic 8/9 Cost of Service Agreement (ER18-1639) | Nov 10 | MA AG, CT Parties, ENECOS appeal *Mystic ROE Order* and *September 13 Notice* (*see* Section XVI) |
| | | | Nov 17 | Mystic answers ENECOS and NESCOE formal challenges to Mystic's 2021 Capital Expenditures Informational Filing |
| | | | Nov 18 | FERC issues *Mystic ROE Allegheny Order*, modifying the discussion in, and setting aside in part, the *Mystic ROE Order* (reducing the ROE from 9.33% to 9.13 %) |

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

| | | | | |
|---|---|---|---|---|
| * | 12 | CSO Termination: Killingly Energy Center (ER22-355) | Nov 4 | ISO-NE files to terminate CSO for Resource 38663 held NTE Connecticut |
| | | | Nov 8-26 | Calpine, CL&P, Emera Energy Services, NEPGA, NESCOE, National Grid, CT AG, CT DEEP, EPSA, Gemma Power Systems, North Atlantic States Regional Council of Carpenters, Public Citizen, Sierra Club, Yankee Gas intervene |
| | | | Nov 24 | NTE Connecticut (Killingly's Project Sponsor) requests a one-week extension of the comment deadline, from Nov 26 to Dec 3, 2021 |
| | 13 | Waiver Request: FCA16 Qualification (Andro Hydro) (ER22-174) | Nov 8 | NEPOOL intervenes |
| | | | Nov 10 | ISO-NE and Pixelle Androscoggin oppose waiver request |
| | 13 | eTariff § III.3.1 Corrections (ER21-2850) | Nov 4 | FERC accepts corrections, eff. Aug 27, 2021 |

## IV. OATT Amendments / TOAs / Coordination Agreements

| | | | | |
|---|---|---|---|---|
| * | 13 | Attachment K Resource Assumption Changes (ER22-400) | Nov 12 | ISO-NE and NEPOOL file changes; comment date ***Dec 3, 2021*** |
| | | | Nov 18, 23 | NESCOE, National Grid intervene |
| | 13 | BTM Generation Proposal (ER21-2337) | Nov 12 | FERC issues deficiency letter; responses due ***Dec 13, 2021*** (submission of responses will re-set the deadline for FERC action) |

## V. Financial Assurance/Billing Policy Amendments

| | | | | |
|---|---|---|---|---|
| | 15 | Removal of FAP Notarization Requirements (ER22-213) | Nov 8 | National Grid intervenes |

## VI. Schedule 20/21/22/23 Changes

| | | | | |
|---|---|---|---|---|
| * | 15 | Sched. 21-VP: 2020 Annual Update Settlement Agreement (ER15-1434-005) | Nov 19 | Versant Power files Settlement Agreement to resolve all issues raised by the MPUC following Versant's 2020 Annual Update filing; comment deadline ***Dec 9, 2021***; reply comments, ***Dec 19, 2021*** |

## VII. NEPOOL Agreement/Participants Agreement Amendments

***No Activity to Report***

## VIII. Regional Reports

| | | | | |
|---|---|---|---|---|
| * | 17 | Interconnection Study Metrics Processing Time Exceedance Report Q3 2021 (ER19-1951) | Nov 12 | ISO-NE files required quarterly report |
| * | 18 | IMM Quarterly Markets Reports - 2021 Summer (ZZ22-4) | Nov 15 | IMM files Summer 2021 Report; to be reviewed at Dec 8-9 Markets Committee meeting |

## IX. Membership Filings

| | | | | |
|---|---|---|---|---|
| * | 18 | December 2021 Membership Filing (ER22-502) | Nov 30 | NEPOOL requests the FERC accept (i) the memberships of BP Energy Retail and PSEG Power CT; (ii) terminations of the Participant status of CHI, JF Gray, Liberty Power DE, South Jersey Energy Co., and South Jersey Energy ISO3; and (iii) the name change of AES Renewables; comment deadline ***Dec 21, 2021*** |
| | 18 | October 2021 Membership Filing (ER21-2985) | Nov 19 | FERC accepts (i) the memberships of CPV Valley; Generation Bridge Connecticut Holdings; Generation Bridge M&M Holdings; J.P. Morgan Ventures Energy Corp.; Oxford Energy; Naugatuck Avenue; Norman Street ESS; and Westfield ESS; and (ii) the name change of Rhode Island Bioenergy Facility, LLC |
| | 18 | Suspension Notice – EIP Investment, LLC (not docketed) | Nov 4 | ISO-NE files notice of suspension of EIP Investment, LLC from the New England Markets |

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

| | | | | |
|---|---|---|---|---|
| | 21 | 2022 NERC/NPCC Business Plans and Budgets (RR21-9) | Nov 2 | FERC approves 2022 NERC and Regional Entity budgets |
| * | 22 | Protection System Commissioning Program Review Report (not docketed) | Nov 4 | FERC/NERC issue joint report |
| * | 22 | Report on Feb 2021 Cold Weather Outages in Texas and the South Central US (not docketed) | Nov 16 | FERC/NERC issue report on Feb 8-20 severe cold weather event, identifying 28 key recommendations to protect against recurrence of just such an event |

## XI. Misc. - of Regional Interest

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|---|---|---|---|---|
| * | 23 | 203 Application: Howard Wind / Greenbacker Wind (EC22-13) | Nov 3 | Greenbacker Wind requests authorization to acquire 100% of the equity interests in Howard Wind LLC from Everpower |
| | 25 | CL&P/EIP E&P Agreement (ER21-2880) | Nov 10 | FERC accepts Agreement, eff. Sep 14, 2021 |
| | 25 | IA Termination: CL&P/Sterling Property (ER21-2860) | Nov 8 | FERC rejects Sterling Property IA termination notice |
| | 26 | *Orders 864/864-A* (Public Util. Trans. ADIT Rate Changes): New England Compliance Filings (various) | Nov 8 | *ER20-2429-001 (CMP).* CMP submits responses to 2nd deficiency letter |
| | | | Nov 22 | *ER20-2133-002 (Versant).* Versant submits joint offer of settlement; comment deadline ***Dec 13, 2021***; reply comment deadline ***Dec 22, 2021*** |
| | | | Nov 24 | *ER21-1293 (NSTAR).* NSTAR proposes limited revisions to its *Order 864* compliance filing; comment deadline ***Dec 6, 2021*** |
| | | | Dec 1 | *ER21-1295 (CL&P).* CL&P proposes limited revisions to its *Order 864* compliance filing; comment deadline ***Dec 22, 2021*** |

## XII. Misc. - Administrative & Rulemaking Proceedings

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| | 27 | Joint Federal-State Task Force on Electric Transmission (AD21-15) | Nov 10 | Joint Federal-State Task Force convenes for its first meeting |
| | | | Nov 22 | FERC issues notice inviting comments on issues raised during the meeting; comment deadline ***Dec 22, 2021*** |
| | 28 | Reliability Technical Conference (Sep 30) (AD21-11) | Nov 16 | FERC posts transcript of Sep 30 tech conf in eLibrary |
| | 29 | Modernizing Electricity Market Design - Energy and Ancillary Service Markets (AD21-10) | Nov 22 | FERC posts transcript of Oct 12 tech conf in eLibrary |

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|---|---|---|---|
| 30 | Office of Public Participation (AD21-9) | Nov 4-19 | Individual ratepayers submit comments |
| | | Nov 9 | PNNL files memo summarizing opportunities related to technical assistance and submitting all workshop documentation into the record |
| 32 | ANOPR: Transmission Planning and Allocation and Generator Interconnection (RM21-17) | Nov 9-30 | Reply comments submitted by over 90 parties, including by: CT AG, Acadia Center/CLF, CT AG, Dominion, Enel, Eversource, LS Power, MA AG, MMWEC, NESCOE, NextEra, Shell, UCS, Vistra, ACPA/ESA, AEE, APPA, EEI, ELCON, Environmental and Renewable Energy Advocates, EPSA, Harvard ELI, NRECA, Potomac Economics, SEIA |
| | | Nov 15 | FERC convenes staff-led, remote technical conference regarding regional transmission planning |
| | | Nov 16 | Speaker materials posted in eLibrary |
| | FERC Composition | Nov 16 | Senate confirms nomination of Willie Phillips, Jr. to be a member of the FERC for a term expiring June 30, 2026 |

## XIII. FERC Enforcement Proceedings

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| 40 | GreenHat (IN18-9) | Nov 5 | FERC issues order (i) assessing civil penalties against GreenHat (***$179 million***), Bartholomew (***$25 million***), and Ziegenhorn (***$25 million***) and (ii) ordering Respondents, including the Kittell Estate, to disgorge unjust profits of just over ***$13 million***, plus interest, with each Respondent jointly and severally liable for payment of that disgorgement amount |
| 42 | Total Gas & Power North America, Inc. et al. (IN12-17) | Nov 9 | Settlement Judge deJesus declares an impasse and recommends that settlement judge procedures be terminated |
| | | Nov 16 | Chief Judge Cintron terminates settlement judge procedures |

## XIV. Natural Gas Proceedings

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| 43 | Iroquois ExC Project (CP20-48) | Nov 12 | FERC staff issues final EIS for the Project |

## XV. State Proceedings & Federal Legislative Proceedings

***No Activity to Report***

## XVI. Federal Courts

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|---|---|---|---|
| 47 | Mystic ROE (21-1198) (consolidated) | Nov 10 | CT Parties, ENECOS, MA AG file Petitions for Review |
| | | Nov 15 | New cases consolidated with and into 21-1998; FERC requests add'l 60 days to file Certified Index to Record |
| 47 | ISO-NE Implementation of *Order 1000* Exemptions for Immediate Need Reliability Projects (20-1422) | Nov 13 | Oral argument scheduled for ***Jan 27, 2022*** |
| 48 | CIP IROL Cost Recovery Rules (20-1389) | Nov 12 | Oral argument held before Judges Srinivasan, Katsas and Randolph |
| 51 | PennEast Project (18-1128) | Nov 12 | Court grants motion to hold case in abeyance; parties directed to file motions to govern future proceedings by ***Feb 18, 2022*** |
| 51 | *Opinion 569/569-A*: FERC's Base ROE Methodology (16-1325 et al.) (consol.) | Nov 18 | Oral argument held before Judges Srinivasan, Katsas and Walker |
| 2 | Algonquin Atlantic Bridge Project Briefing Order (21-1115 et al.) (consol.) | Nov 15 | Court granted third abeyance motion; parties directed to file motions to govern future proceedings by ***Jan 31, 2022*** |

**M E M O R A N D U M**

**TO:** NEPOOL Participants Committee Members and Alternates

**FROM:** Patrick M. Gerity, NEPOOL Counsel

**DATE:** December 1, 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 December 1, 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)**

As previously reported, the FERC instituted on September 7, 2021 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 [FERC]'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. On September 8, the FERC issued a notice of the proceeding and of the refund 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.[14] NEPOOL, NESCOE, Brookfield, Calpine, Dominion, Eversource, HQ US, LS Power, MA AG, MMWEC, National Grid, NECEC Transmission, NEPGA, NextEra, NRG, CT DEEP, MA DOER, Pixelle Androscoggin (out-of-time), Vistra (out-of-time), American Clean Power Association ("ACPA"), EPSA, RENEW Northeast, and Public Citizen intervened.

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

***ISO-NE Answer***. On November 8, 2021, ISO-NE submitted its answer explaining why Schedule 25 and Tariff section I.3.10 remain just and reasonable. ISO-NE called for the FERC to assist "assist Affected Parties and Interconnection Customers in resolving any disputes pertaining to upgrades on Affected Systems—such as the dispute between NECEC Transmission and NextEra Energy Seabrook, LLC in Docket No. EL21-6—as quickly as possible." Interested parties have 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.

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)**

As previously reported, on September 23, 2021, the FERC denied in part, but granted in part, the complaint ("Complaint")[15] by Green Development, LLC ("Green Development") against New England Power Company and Narragansett Electric Company (together, "National Grid" or "Grid").[16] The *Complaint Order* partially denied the Complaint, finding that Green Development did not meet its burden of proof that the assignment of Direct Assignment Facility ("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).[17] 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."[18] 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.[19]

***Request for Partial Rehearing Denied by Operation of Law***. On November 26, 2021, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[20] The Notice confirmed that the 60-day period during which a petition for review of the *Green Development Complaint Order* can be filed with an appropriate federal court was triggered when the FERC did not act on Green Development's request for partial rehearing of the *Complaint Order*.[21] 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."

[15] 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").

[16] 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*")).

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

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

[19] *Id.* at P 62.

[20] *Green Development, LLC v. New England Power Co. and Narragansett Elec. Co.*, 177 FERC ¶ 62,099 (Nov. 26, 2021) ("*Green Development Complaint Allegheny Order*").

[21] On October 25, 2021, Green Development requested partial rehearing of the *Green Development Complaint Order*, asking the FERC to reverse its 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 DAF (requiring that the facilities be constructed for the sole use/benefit of a particular Transmission Customer requesting service under the ISO-NE Tariff), and grant its Complaint in full.

If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@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[22] 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.

***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).[23] Initial briefs[24] were due on or before October 7, 2021, and were filed by ISO-NE, Avangrid, NextEra, MA AG, NEPGA/EPSA, MA DOER. Reply briefs were due on or before October 22, 2021, and were filed by Avangrid, NextEra, ISO-NE. Since the last Report, Avangrid answered NextEra's November 4 answer, NextEra moved to lodge a letter from a Branch Chief of the Nuclear Regulatory Commission ("NRC"), including an Inspection Report for Seabrook Station for the time period from July 1, 2021 through September 30, 2021 (together, the "NRC Seabrook Report"), to directly refute a central claim of Avangrid (that Seabrook should have already replaced the Generation Breaker at issue in this proceeding), and Avangrid opposed that motion to lodge (asserting that the NRC Seabrook Report is outside the scope of these

[22] 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.

[23] *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).

[24] The FERC requested additional briefing from the Parties, as well as from ISO-NE, on the following issues: (i) whether or not Seabrook's breaker is properly identified as a part of Seabrook's generating facility; (ii) 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; (iii) 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; (iv) whether there exists any solution for the interconnection of the NECEC Project that may be implemented without the replacement of Seabrook's breaker; and (v) 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.

proceedings and will not assist the FERC in its decision making). With briefing complete, this matter is again before the FERC, which is expected to issue an order in late January, 2022.

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. Since the last Report, NextEra moved to lodge the NRC Seabrook Report. 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).

- **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,[25] 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*).[26] However, the FERC's orders were challenged, and in *Emera Maine,*[27] the DC Circuit vacated the FERC's prior orders, and remanded the case for further proceedings consistent with its

[25] 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*")).

[26] *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*").

[27] *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).

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)[28] and third (EL14-86)[29] 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.[30] 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[31] also went to hearing before an ALJ, Judge Glazer, who issued his initial decision on March 27, 2017.[32] The *Base ROE IV Initial Decision* concluded that the currently-filed base ROE of 10.57%, which may reach a maximum ROE of 11.74% with incentive adders, was ***not*** unjust and unreasonable for the Complaint IV period, and hence was not unlawful under section 206 of the FPA.[33] 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.[34] 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*[35] (EL14-12; EL15-45) in

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[28] 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%.

[29] 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.

[30] *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*").

[31] 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.

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

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

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

[35] *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

Section XI below). The FERC established a paper hearing on how its proposed methodology should apply to the four pending ROE proceedings.[36]

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%.[37] The new ROE would be effective as of the date of *Opinion 531-A*, or October 16, 2014. Accordingly, the issue to be addressed in the Base ROE Complaint II proceeding is whether the ROE established on remand in the first complaint proceeding remained just and reasonable based on financial data for the six-month period September 2013 through February 2014 addressed by the evidence presented by the participants in the second proceeding. Similarly, briefing in the third and fourth complaints will have to address whether whatever ROE is in effect as a result of the immediately preceding complaint proceeding continues to be just and reasonable.

The FERC directed participants in the four proceedings to submit briefs regarding the proposed approaches to the FPA section 206 inquiry and how to apply them to the complaints (separate briefs for each proceeding). Additional financial data or evidence concerning economic conditions in any proceeding must relate to periods before the conclusion of the hearings in the relevant complaint proceeding. Following a FERC notice granting a request by the TOs and Customers[38] 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

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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*.

[36] *Id.* at P 19.

[37] *Id.* at P 59.

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

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*[39] 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

- **ICR-Related Values and HQICCs – Annual Reconfiguration Auctions (ER22- )**

On November 30, 2021, ISO-NE and NEPOOL jointly filed materials that identify the Installed Capacity Requirement ("ICR"), Local Sourcing Requirements ("LSR"), Maximum Capacity Limits ("MCL"), Hydro Quebec Interconnection Capability Credits ("HQICCs"), and capacity requirement values for the System-Wide and Marginal Reliability Impact Capacity Demand Curves (collectively, the "ICR-Related Values") for the third annual reconfiguration auction ("ARA") for the 2022-23 Capability Year, the second ARA for the 2023-24 Capability Year, and the first ARA for the 2024-25 Capability Year. The ICR-Related Values were supported by the Participants Committee at its November 3, 2021 meeting (Consent Agenda Items 3 and 4). A January 29, 2022 effective date was requested. Comments on this filing are due December 21, 2021. If you have any questions concerning these matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **FCA16 Qualification Informational Filing (ER21-391)**

On November 9, 2021, ISO-NE submitted its informational filing (the "FCA16 Informational Filing") for qualification in FCA16. ISO-NE is required under Market Rule Section 13.8.1 to submit an informational filing with the FERC containing the determinations made by ISO-NE for the upcoming Forward Capacity Auction ("FCA") at least 90 days prior to each auction. FCA16 is scheduled to begin February 7, 2022. The Informational Filing contained ISO-NE's determinations that four Capacity Zones will be modelled for FCA15 -- Southeastern New England ("SENE"), Northern New England ("NNE"), the Maine Capacity Zone ("Maine"), and Rest of Pool. SENE will again be modeled as import-constrained; NNE will be modeled as export-constrained. The Maine Load Zone will be modeled as a separate nested export-constrained Capacity Zone within NNE. The Informational Filing reported that there will be 33,356 MW of existing capacity in FCA16 competing with 5,246 MW of new capacity under a Net ICR of 31,645 MW (ICR minus HQICCs). ISO-NE reported also that there were a total of 503 MW of Static De-List Bids. A summary of the De-List Bids accepted and those rejected for reliability purposes was included in a privileged Attachment E. ISO-NE qualified 15 demand bids, totaling 994 MW, and 193 supply offers, totaling 779 MW, to participate in the substitution auction.

Comments on the FCA16 Informational Filing were due November 24, 2021. Protests were filed by Borrego Solar Systems ("Borrego") and jointly by Anbaric Development Partners, LLC ("Anbaric") and Massachusetts Municipal Wholesale Electric Company ("MMWEC"). Each protested the basis for the IMM's mitigation of a storage resource – for ***Borrego***, the mitigation to zero of an assumed 26.2% percent value for a storage Investment Tax Credit ("ITC") included in the "Build Back Better Act" that had not yet, but has since, been passed; for ***Anbaric/MMWEC***, the IMM's rejection of project-specific offer components that rely on either documented competitive advantages enjoyed by each of Anbaric/MMWEC or on FERC-approved storage ORTP offer components. Doc-less interventions only were filed by NEPOOL, Calpine, Dominion, ENE

[39] *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).

(out-of-time), Eversource, National Grid, NESCOE, NRG, and the MA DPU. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **ICR-Related Values and HQICCs – FCA16 (2025-26) Capacity Commitment Period (ER22-378)**

On November 9, 2021, ISO-NE filed the ICR, LSR for SENE, MCL for the Maine and NNE Capacity Zones, HQICCs, and Marginal Reliability Impact ("MRI") Demand Curves (collectively, the "2025-26 ICR-Related Values") for the 2025-26 Capacity Commitment Period ("CCP"). The 2025-26 ICR will be 32,568 MW (reflecting tie benefits of 1,830 MW) and HQICCs of 923 MW/mo., the net amount of capacity to be purchased in FCA16 to meet the ICR will be 31,645 MW. The LSR for the SENE Capacity Zone is 9,450 MW. The MCL for the Maine Capacity Zone is 4,095 MW. The MCL for the NNE Capacity Zone is 8,555 MW. The Participants Committee supported the FAC16 ICR-Related Values at its October 7, 2021 meeting. Comments on this filing were due November 30, 2021. Comments were filed by Climate Code Blue, a group of Massachusetts physicians advocating for a healthier climate, and Greater Boston Physicians for Social Responsibility. Those organizations, noting their disagreement with an "every electron is neutral policy that results in the same priority given to fossil fuel-based resources as to renewable energy sources" (highlighting Merrimack Generating Station), requested that the FERC "guide the ISO New England to change their algorithm to incentivize clean, sustainable, renewable energy. We also ask for greater transparency and public participation in ISO-New England's grid transition planning." Doc-less interventions were filed by NEPOOL, Calpine, Dominion, Eversource, MA DPU, National Grid, NESCOE, and NRG. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Sophia Browning (202-218-3904; sbrowning@daypitney.com).

- **2021 NESCOE Budget (2022 NESCOE Budget (ER22-117)**

This proceeding was initiated by ISO-NE's October 15, 2021 filing of the budget for funding NESCOE's 2022 operations. The 2022 Operating Expense Budget for NESCOE is $2,485,156. The amount to be recovered reflects true-ups from 2021 (over-collections of $781,482). Accordingly, if accepted, the NESCOE budget will result in a charge of $0.00736 per kilowatt ("kW") of Monthly Network Load (a $0.00110/kW increase over 2021). The 2022 NESCOE budget was supported by the Participants Committee at its October 7, 2021 meeting. Comments and any interventions were due on or before November 5. NEPOOL filed comments supporting the 2022 NESCOE Budget. Doc-less interventions only were filed by NESCOE, Eversource, MA DPU, and National Grid. This matter is pending before the FERC. If there are any questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **2022 ISO-NE Administrative Costs and Capital Budgets (ER22-113)**

On October 15, 2021, ISO-NE filed for recovery of its 2022 administrative costs (the "2022 Revenue Requirement") and submitted its capital budget and supporting materials for calendar year 2022 ("2022 Capital Budget", and together with the 2022 Revenue Requirement, the "2022 ISO Budgets"). The 2022 ISO-NE Budgets were filed together pursuant to the Settlement Agreement entered into to resolve challenges to the 2013 ISO-NE Budgets. In the October 15 filing, ISO-NE reported that the 2022 Revenue Requirement is $215.1 million (a $10.1 million or 4.9% increase over 2021), which increases to $216.1 million after the under-collection for 2020 is added. Of that total, ISO-NE's administrative costs (i.e., the 2022 Core Operating Budget) comprise $189.1 million; depreciation and amortization of regulatory assets, $26 million; and a $1.1 million true-up for 2020 under-collections.

ISO-NE further reported that the 2022 Capital Budget is $32 million, a $4 million increase over 2021, and is comprised of the following (with 2022 projected costs and target completion dates, if available, in parentheses):

- nGem Market Clearing Engine Implementation (Mar 2023) ($4.4 million)
- nGem Software Development Part II (Dec 2022) ($2.8 million)

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| ‣ nGem Hardware Phase II (Dec 2022) | ($3 million) | ‣ Forward Capacity Tracking System Infrastructure Conversation Part III (Dec 2022) | ($2.9 million) |
| ‣ Cyber Security Improvements (Dec 2022) | ($2 million) | ‣ 2022 Issue Resolution Projects (June 2022 and Dec 2022) | ($1.5 million) |
| ‣ MOPR (Dec 2023) | ($1.5 million) | ‣ Amazon Web Services Cloud Foundation (Apr 2022) | ($1 million) |
| ‣ CIP Electronic Security Perimeter Redesign Phase II | ($1 million) | ‣ IMM Data Analysis Phase III (Dec 2022) | ($900,000) |
| ‣ IMM Data Analysis Phase III (Dec 2022) | ($900,000) | ‣ Linear State Estimator (Oct 2022) | ($500,000) |
| ‣ Solar Do Not Exceed Dispatch (Sep 2022) | ($500,000) | ‣ Enterprise Application Integration Phase III (Nov 2022) | ($500,000) |
| ‣ Integrated Market Simulator Phase I (Jun 2022) | ($400,000) | ‣ External Website Migration to Cloud (Oct 2022) | ($400,000) |
| ‣ Identity and Access Management – Phase III (Dec 2022) | ($400,000) | ‣ Integrated Market Simulator Phase I (Jun 2022) | ($400,000) |
| ‣ Windows Server 2019 R2 Deployment (Jun 2023) | ($400,000) | ‣ Security Information and Event Management Log Monitoring Replacement (Jul 2022) | ($300,000) |
| ‣ Forward Capacity Market Cost Allocation & Accelerated Billing (May 2022) | ($300,000) | ‣ Security Information and Event Management Log Monitoring Replacement (Jul 2022) | ($300,000) |
| ‣ TTC Calculator Redesign (May 2022) | ($300,000) | ‣ TranSMART Technical Architecture Update (Jun 2022) | ($300,000) |
| ‣ TranSMART Technical Architecture Update (Jun 2022) | ($300,000) | ‣ E-mail List Server Technology Refresh (Jan 2023) | ($300,000) |
| ‣ Forecast Enhancements (Jun 2020) | ($200,000) | ‣ Capitalized Interest | ($500,000) |
| ‣ LMP Monitor Replacement (Apr 2022) | ($100,000) | ‣ Non-Project Capital Expenditures | ($3 million) |
| | | ‣ Other Emerging Work | ($2.4 million) |

The 2022 ISO-NE Budgets were supported by the Participants Committee at its October 7, 2021 meeting. Comments on this filing were due November 5, 2021. NEPOOL filed comments supporting the 2022 Budgets on November 1. Doc-less interventions were filed by Eversource, National Grid and NRG. This matter is pending before the FERC. If there are any questions on this matter, please contact Paul Belval (860-275-0381; pnbelval@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[40] 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

[40] 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).[41] Relying on its *Schedule 17 Orders*,[42] 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.[43] The FERC rejected the alternative bases for FERC approval proposed by CSC.[44]

***CSC Request for Rehearing Denied by Operation of Law***. On November 1, 2021, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[45] The Notice confirmed that the 60-day period during which a petition for review of the *August 31 Order* can be filed with an appropriate federal court was triggered when the FERC did not act on CSC's request for rehearing of the *August 31 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." There was no activity in this proceeding since the last Report.

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)**

Each of the *July 17 Orders*[46] and the *Mystic ROE Order,*[47] which addressed in part or in whole the Cost-of-Service Agreement ("COS Agreement")[48] among Constellation Mystic Power ("Mystic"), Exelon Generation Company ("ExGen"), have been appealed to the U.S. Court of Appeals for the D.C. Circuit ("DC Circuit") (*see* Section XVI below). Since the last Report:

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

42 *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).

43 *August 31 Order* at P 33.

44 *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.

45 *Cross-Sound Cable Co., LLC*, 177 FERC ¶ 62,064 (Nov. 1, 2021) (Notice of Denial By Operation of Law of Rehearings of *August 31 Order*).

46 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).

47 *Constellation Mystic Power, LLC,* 176 FERC ¶ 61,019 (July 15, 2021) ("*Mystic ROE Order*") (setting the base ROE for the Mystic COS Agreement at 9.33%).

48 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.

***Mystic ROE Allegheny Order.*** On November 18, 2021, the FERC issued an "Allegheny Order"[49] modifying the discussion in the *Mystic ROE Order* and setting aside that *Order*, in part.[50] In particular, agreeing with Connecticut Parties that "Otter Tail is properly excluded [as an outlier] from the [Discounted Cash Flow model ("DCF")] under the natural break analysis", the FERC found that the resulting average of the medians of the DCF, Capital Asset Pricing, and Risk Premium models (which sets the ROE) is 9.19%.[51] According the FERC directed Mystic to submit a compliance filing revising the Mystic Agreement to reflect a 9.19% (rather than a 9.33%) base ROE. The FERC also clarified that Avangrid's exclusion from the proxy group was based on its controlled status (ownership stakes by a single entity greater than 50%) and not on the particulars of Iberdrola's ownership or operations.[52] The FERC either disagreed with or dismissed as repetitive the remainder of the parties' arguments on rehearing. Mystic's (sixth) compliance filing is due on or before December 18, 2021.

***First CapEx Info. 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 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 ("First CapEx Projects Info. Filing"). Formal challenges to the September 15 filing were submitted by the Eastern New England Customer-Owned Systems ("ENECOS") and NESCOE. Comments on the formal challenges were due on or before November 17, 2021, and Mystic responded on November 17 asserting that that the challenges should be rejected without further procedures. The formal challenges are pending before 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).

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

- **CSO Termination: Killingly Energy Center (ER22-355)**

Pursuant to Market Rule 1 § 13.3.4(c), ISO-NE filed on November 4, 2021 to terminate the CSO held by Project Sponsor NTE Connecticut LLC ("NTE CT") for Resource No. 38633, the Killingly Energy Center. ISO-NE explained that the involuntary termination was being submitted because a trigger for termination under Section III.13.4.3A had been met. ISO-NE indicated that, upon FERC acceptance of the filing, it will draw down the amount of financial assurance provided by NTE CT with respect to the Killingly CSO and Killingly will be ineligible to participate in FCA16. Comments on this filing were due on or before November 26. On November 24, NTE CT requested a one-week extension of time, to December 4, 2021, to respond to ISO-NE's filing. Answers to NTE's motion are due on or before December 2, 2021. Doc-less interventions were filed by Calpine, CL&P, Emera Energy Services, NEPGA, NESCOE, National Grid, CT AG, CT DEEP, EPSA, Gemma Power Systems, North Atlantic States Regional Council of Carpenters, Public Citizen, Sierra Club, and Yankee Gas. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

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[49] An "Allegheny Order" is a merits rehearing order issued on or after the 31st day after receipt of a rehearing request, reflecting the FERC's authority to "modify or set aside, in whole or in part," its order until it files the record on appeal with a reviewing federal court. An Allegheny Order will use "modifying the discussion" if the FERC is providing a further explanation, but is not changing the outcome, of the underlying order; or "set aside" if the FERC is changing the outcome of the underlying order. Aggrieved parties have 60 days after a deemed denial to file a review petition, even if FERC has announced its intention to issue a further merits order.

[50] *Constellation Mystic Power, LLC*, 177 FERC ¶ 61,106 (Nov. 18, 2021) ("*Mystic ROE Allegheny Order*") (re-setting Mystic's ROE to 9.19%).

[51] *Id.* at P 15.

[52] *Id.* at P 21.

- **Waiver Request: FCA16 Qualification (Andro Hydro) (ER22-174)**

On October 20, 2021, as supplemented on October 26, Andro Hydro LLC ("Andro Hydro") requested a one-time waiver of the FCM qualification rules to allow Andro Hydro's Riley-Jay-Otis-Livermore hydroelectric generating resource to participate in the sixteenth Forward Capacity Auction ("FCA16") at a reduced qualification level (8 MW rather than 12.884 MW). Andro Hydro states that ISO-NE informed it of its determination just one day ahead of the Tariff deadline to reduce the capacity amount for which FCA16 qualification sought, insufficient time for it to understand and address ISO-NE's determination.[53] Andro Hydro seeks all necessary waivers to allow it to lower the FCA16 MWs for its resource (avoiding any concerns regarding required upgrades), and thereby make it possible for its resource to participate in FCA16. Comments on Andro Hydro's waiver request were due on or before November 10, 2021. Oppositions to Andro Hydro's request were filed by ISO-NE and Pixelle Androscoggin, LLC. NEPOOL filed a doc-less motion to intervene. 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).

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

On November 4, 2021, the FERC accepted conforming changes to eTariff § III.3.1 filed by ISO-NE 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).[54] The changes were accepted for filing, effective August 27, 2021, as requested. Unless the November 4 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).

## IV. OATT Amendments / TOAs / Coordination Agreements

- **Attachment K Resource Assumption Changes (ER22-400)**

On November 12, 2021, ISO-NE and NEPOOL jointly filed Tariff revisions (i) to expand the resources that may be relied upon in certain transmission planning studies and (ii) to clarify language in Attachment K (collectively, the "Attachment K Resource Assumption Changes"). With the Attachment K Resource Assumption Changes, ISO-NE will include all existing resources, with the exception of imports, in Needs Assessments and Public Policy Transmission Studies. A January 11, 2022 effective date was requested. The Participants Committee unanimously supported the Attachment K Resource Assumption Changes at its October 7, 2021 meeting (Agenda Item 7). Comments on this filing are due on or before December 3, 2021. Thus far, doc-less interventions have been filed by National Grid and NESCOE. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **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.

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[53] ISO-NE determined that Andro Hydro's resource did not qualify to participate in FCA16 because a portion of the administered transmission system owned by CMP would require upgrades (not expected to be upgraded before the 2025-2026 Capacity Commitment Period ("CCP")) to allow the Resource to supply capacity.

[54] *ISO New England Inc.*, Docket No. ER21-2850 (Nov. 4, 2021) (unpublished letter order).

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.

***Deficiency Letter I***. 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. Comments on ISO-NE's deficiency letter responses were due on or before October 12, 2021, and NEPGA filed an amended protest and comments on that day. On October 27, the PTO AC answered NEPGA's amended protest and comments.

***Deficiency Letter II***. On November 12, 2021, the FERC issued a second deficiency letter, directing ISO-NE to provide within 30 days further additional information.[55] The responses to the Deficiency Letter are due on or before December 13, 2021. The responses to the second deficiency letter will re-set again the 60-day deadline for FERC action on this filing.

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.

***Amended Revisions (ER21-2529-001)***. On October 22, 2021, the PTO AC submitted amendments to the July 27 compliance filing to include in Schedules 20A-Common and 21-Common revised and new WEQ standards identified in the FERC's March 3, 2020 errata notice to *Order 676-I* ("*Order 676-I Errata Notice*") but not included in the July 27, 2021 filing. Any comments on the errata filing are due on or before November 12, 2021.

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.

***Amended Revisions (ER21-2509-001)***. On October 27, 2021, ISO-NE and CSC submitted amendments to the July 26 compliance filing to include in Schedule 18 revised and new WEQ standards identified in the FERC's *Order 676-I Errata Notice* but not included in the July 26, 2021 filing. Any comments on the errata filing are due on or before November 17, 2021.

[55] Specifically, ISO-NE must (i) provide additional support or information regarding the current practices of TOs in calculating Monthly RNL and an illustrative example and a narrative explanation of how transmission costs would be reallocated among Network Customers as a result of the proposal; and (ii) an explanation as to how Filing Parties' proposal is consistent with transmission planning practices with respect to the treatment of BTM generation.

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.

***Amended Revisions (ER21-941-001)***. On October 22, 2021, ISO-NE and NEPOOL submitted amendments to the January 26 compliance filing to include in Schedule 24 revised and new WEQ standards identified in the *Order 676-I Errata Notice* to but not included in the July 26, 2021 filing. Any comments on the errata filing are due on or before November 12, 2021.

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

## V. Financial Assurance/Billing Policy Amendments

- **Removal of FAP Notarization Requirements (ER22-213)**

On October 27, ISO-NE and NEPOOL jointly filed changes to the ISO-NE Financial Assurance Policy ("FAP") to remove the notarization requirement from the FAP officer certification forms and to add a statement of acknowledgment of the Senior Officer executing the officer certification forms ("FAP Revisions"). The FAP Revisions were unanimously approved at the October 7, 2021 Participants Committee meeting. ISO-NE requested a January 1, 2022 effective date for the FAP Revisions, which dovetails with the expiration of the FERC's blanket waiver of Tariff notarization requirements described in Section I above. Comments on the FAP Revisions were due on or before November 17, 2021; none were filed. National Grid filed a doc-less intervention. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

## VI. Schedule 20/21/22/23 Changes

- **Schedule 21-NEP: Sterling Municipal LSA (ER22-97)**

On October 13, 2021, National Grid filed a non-conforming Local Service Agreement ("LSA") with Sterling Municipal Light Department ("Sterling Municipal") to extend the term of service to Sterling Municipal and to include the other new provisions, particularly those related to the DAF Charge that Sterling Municipal is required to pay pursuant to the LSA. Since the LSA covers an existing, interconnected facility, a new three-party interconnection agreement (that would include ISO-NE) was not required. A December 13, 2021 effective was requested. Comments on this filing were due on or before November 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).

- **Schedule 21-VP: 2020 Annual Update Settlement Agreement (ER15-1434-005)**

On November 19, 2021, Versant Power submitted a joint offer of settlement between itself and the MPUC to resolve all issues raised by the MPUC in response to Versant's 2020 annual charges update filed, as previously reported, on June 15, 2020 (the "Versant 2020 Annual Update Settlement Agreement"). Under Part V of Attachment P-EM to Schedule 21-VP, "Interested Parties shall have the opportunity to conduct discovery seeking any information relevant to implementation of the [Attachment P-EM] Rate Formula. . . ." and follow a dispute resolution procedure set forth there. In accordance with those provisions, the MPUC identified certain disputes with the 2020 Annual Update, all of which are resolved by the Versant 2020 Annual

Update Settlement Agreement. Comments on the Versant 2020 Annual Update Settlement Agreement are due on or before December 9, 2021; reply comments, December 19, 2021. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@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,*[56] and certified by Settlement Judge Dring[57] to the Commission.[58] 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 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).

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[56] *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.

[57] 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.

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

- **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*[59] *and 531-B*[60] also remains pending. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- ***Opinions 531-A/531-B* Local Refund Reports (EL11-66)**

The *Opinions 531-A and 531-B* refund reports filed by the following TOs for their customers taking local service during the refund period also remain pending before the FERC:

- Central Maine Power
- Emera Maine
- Eversource
- National Grid
- NHT
- NSTAR
- United Illuminating
- VTransco

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

- **Capital Projects Report - 2021 Q3 (ER22-125)**

On October 15, 2021, ISO-NE filed its Capital Projects Report and Unamortized Cost Schedule covering the third quarter ("Q3") of calendar year 2021 (the "Report").[61] Report highlights included the following new projects: (i) E-Mail List Server Technology Refresh ($769,000); and (ii) Total Transfer Capability ("TTC") Calculator Redesign ($492,400). Projects with a significant changes (with amounts returned to the Emerging Work Fund following in parentheses) were (i) Secure Lightweight Directory Access Protocol ("LDAP") Channel Binding Adaption ($100,000); and (ii) 2021 Issue Resolution Project ($100,000). Comments on the 2021 Q3 Report were due on or before November 5, 2021. NEPOOL filed comments supporting the 2021 Q3 Report on November 1, 2021. National Grid filed a doc-less motion to intervene. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **Interconnection Study Metrics Processing Time Exceedance Report Q3 2021 (ER19-1951)**

On November 12, 2021, ISO-NE filed, as required,[62] public and confidential[63] versions of its Interconnection Study Metrics Processing Time Exceedance Report (the "Exceedance Report") for the third quarter of 2021 ("2021 Q3"). ISO-NE reported that:

- ***Interconnection Feasibility Study ("IFS") Reports.*** 8 of the 14 2021 Q3 IFS Reports delivered to Interconnection Customers were delivered later than the best efforts completion timeline.[64] In addition, three IFS Reports that are not yet completed have exceeded the 90 day completion expectation. The average mean time from ISO-NE's receipt of the executed IFS Agreement to delivery of the completed IFS Report to the Interconnection Customer was 124 days (approximately 30 days more than 2021 Q2).

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

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

[61] *ISO New England Inc.*, Docket No. ER21-2632 (Oct. 1, 2021) (unpublished letter order).

[62] 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.

[63] 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.

[64] 90 days from the Interconnection Customer's execution of the study agreement.

- ***System Impact Study ("SIS") Reports.*** Four SIS Reports were delivered to Interconnection Customers, with three delivered later than the best efforts completion timeline of 270 days. The average mean time from ISO-NE's receipt of the executed SIS Agreement to delivery of the completed SIS Report to the Interconnection Customer was 422.5 days (53 days less than 2021 Q2).

- ***Facility Study Reports.*** One Facility Study Report was delivered to an Interconnection Customer and it was delivered later than the best efforts completion timeline of 90 days to refine the costs to the 20% range. In addition, no Facility Studies that are in process have exceeded the 90-day/180-day completion expectation. The time from executed Facility Study Agreement receipt to delivery of the completed Facility Study report to the Interconnection Customer was 147 days.

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.

- **IMM Quarterly Markets Reports – Summer 2021 (ZZ22-4)**

On November 15, 2021, the IMM filed with the FERC its Summer 2021 report of "market data regularly collected by [the IMM] in the course of carrying out its functions under … Appendix A and analysis of such market data," as required pursuant to Section 12.2.2 of Appendix A to Market Rule 1. These filings are not noticed for public comment by the FERC. The Summer 2021 Report will be discussed with the Markets Committee at the December 7-8, 2021 Markets Committee meeting.

## IX. Membership Filings

- **December 2021 Membership Filing (ER22-502)**

On November 30, 2021, NEPOOL requested that the FERC accept (i) the memberships of BP Retail Energy LLC [Related Person to BP Energy Co. (Supplier Sector)]; and PSEG Power Connecticut LLC [Related Person to PSEG Energy Resources & Trade and PSEG New Haven (Supplier Sector)]; (ii) the termination of the Participant status of CHI Power Marketing, Inc. (Supplier Sector); J. F. Gray & Associates, LLC (End User Sector); Liberty Power Delaware LLC (Supplier Sector); South Jersey Energy Company and South Jersey Energy ISO3 (together "South Jersey") (Supplier Sector); and (iii) the name change of AES Renewable Holdings, LLC (f/k/a AES Distributed Energy, Inc.). Comments on this filing are due on or before December 21, 2021.

- **October 2021 Membership Filing (ER21-2985)**

On November 19, 2021, the FERC accepted (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 Member)]; and (ii) the name change of Rhode Island Bioenergy Facility, LLC (f/k/a Orbit Energy Rhode Island, LLC).[65] Unless the November 19 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:

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[65] *New England Power Pool Participants Committee*, Docket No. ER21-2985 (Nov. 19, 2021) (unpublished letter order).

| *Date of Suspension/ FERC Notice* | *Participant Name* | *Default Type* | *Date Reinstated* |
|---|---|---|---|
| Nov 2/4 | EIP Investment, LLC | Financial Assurance | not yet |

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 were due on or before October 6, 2021; none were filed. This matter is pending before the FERC.

- **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"):

- 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"), American Public Power Association ( "APPA")/ Large Public Power Council ("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, the Transmission Access Policy Study Group ("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.[66] On March 25, 2020, Joint Associations[67] 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.

In part in response to the comments filed, the FERC, in a December 17, 2020 order,[68] 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,[69] 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."[70] 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

[66] *Virtualization and Cloud Computing Services*, 170 FERC ¶ 61,110 (Feb. 20, 2020).

[67] "Joint Associations" are for purposes of this proceeding: EEI, APPA, NRECA, and LPPC.

[68] *Virtualization and Cloud Computing Services*, 173 FERC ¶ 61,243 (Dec. 17, 2020) ("*Order Directing Jan 2022 Info. Filing*").

[69] *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).

[70] *Order 873* at P 2.

requirement R8, the FERC remanded the retirement of requirements R7 and R8 to NERC for further consideration.[71]

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*[72] (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 were due on or before October 20, 2021. Comments were filed by Public Utility District No. 1 of Chelan County and jointly by APPA/LPPC/TAPS. This matter is pending before the FERC.

- **2022 NERC/NPCC Business Plans and Budgets (RR21-9)**

On November 2, 2021, the FERC accepted NERC's proposed 2022 Business Plan and Budget, as well as the 2022 Business Plans and Budgets for the Regional Entities, including NPCC, and authorized the issuance of billing invoices to fund the fiscal year 2022 operations of those Entities.[73] As previously reported, NERC's 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's budget includes $17.5 million in statutory funding (a U.S. assessment per kWh (2020 NEL) of $0.0000540) and $1 million for non-statutory functions. Unless the November 2 order is challenged, this proceeding will be concluded.

- **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

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[71] *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.

[72] *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.

[73] *N. Amer. Elec. Rel. Corp.*, 177 FERC ¶ 61,078 (Nov. 2, 2021).

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.[74] The report concluded that 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.

- **FERC/NERC Joint Report on Review of Protection System Commissioning Programs (not docketed)**

On November 4, 2021, FERC Staff, together with staff from NERC and its regional entities issued a report summarizing their review of, and outlining recommendations for, Protection System Commissioning ("PSC") Programs. The review was initiated in 2019 after Misoperation Information Data Analysis System ("MIDAS") data indicated that between 18 and 36 percent of misoperations in MIDAS could be attributed to issues that should have been detected through PSC. The goal of the review was to reduce misoperations attributable to PSC by identifying opportunities for improvement and developing recommendations and best practices for registered transmission and generator owners' PSC programs. View the Report here.

- **FERC/NERC Joint Report on the February 2021 Cold Weather Outages in Texas and the South Central United States (not docketed)**

On November 16, 2021, FERC Staff, together with staff from NERC and its regional entities issued a report describing the severe cold weather event occurring between February 8 and 20, 2021 and how it impacted the reliability of the bulk electric system in Texas and the South Central United States. To prevent recurrence of just such an event, the report identifies 28 key recommendations, together with proposed timeframes for implementation, focused on revisions to the Reliability Standards, actions to prevent electric generating unit and natural gas infrastructure freezing issues, grid operations and gas-electric coordination measures for cold weather preparedness. View the Report here.

[74] 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 maintain situational awareness. The review included on-site discussions with representatives of nine participating reliability coordinators and transmission operators.

## XI. Misc. - of Regional Interest

- **203 Application: Howard Wind / Greenbacker Wind (EC22-13)**

On November 3, 2021, Greenbacker Wind, LLC requested authorization to acquire from Everpower Wind Holdings, Inc. ("Everpower"), 100% of the equity interests in Howard Wind LLC. Comments on this application were due on or before November 24, 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: Castleton Commodities/Atlas Power (GSP companies) (EC22-7)**

On October 20, 2021, ACR II Granite Shore Power Holdings LLC, an Atlas Capital Resources affiliate (together, "Atlas"), and 50% of owner of Granite Shore Power Holdings LLC ("GSP Holdings"), requested authorization to acquire the remaining 50% of GSP Holdings from CCI PAH II, an indirect subsidiary of Castleton Commodities International LLC ("CCI"). Following consummation of the transaction, Atlas will wholly own GSP Holdings, the indirect owner of NEPOOL members GSP Lost Nation LLC, GSP Merrimack LLC, GSP Newington LLC, GSP Schiller LLC, and GSP White Lake LLC. Comments on this application were due on or before November 10, 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: Hull Street/CMEEC (EC22-3)**

On October 15, 2021, MPH AL Pierce, LLC, indirectly owned by affiliates of Hull Street Energy, requested FERC authorization to acquire 100 % of the interests in CMEEC's 84 MW Wallingford electric generating facility. Comments on this application were due on or before November 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).

- **203 Application: PSEG/Generation Bridge II (ArcLight) (EC21-125)**

On September 2, 2021, PSEG Project Companies[75] 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 were due on or before November 2, 2021; none were filed. This application remains pending before the FERC. 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 October 15, 2021, the FERC authorized a transaction pursuant to which Valcour Wind Energy, LLC ("Valcour") will become a Related Person of AES Corporation (and AES Distributed Energy, Inc.).[76] Challenges, if any, to the October 15 order are due on or before November 15, 2021. Pursuant to the October 15 order, AES must file a notice 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).

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[75] 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").

[76] *The AES Corp.*, 177 FERC ¶ 62,026 (Oct. 15, 2021).

- **203 Application: Covanta/EQT (EC21-113)**

On October 18, 2021, the FERC authorized a transaction pursuant to which Covanta Holding Corporation and its public utility subsidiaries, including NEPOOL member Covanta Energy Marketing, LLC (together, "Covanta"), will become a wholly-owned subsidiary Covert Intermediate, Inc., itself an indirectly, wholly-owned affiliate of EQT AB ("EQT").[77] Consummation of this and the Cypress Creek Holdings transaction summarized just below, will make Covanta and Cypress Creek Renewables Related Persons. Pursuant to the October 18 order, Covanta must file a notice 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").[78] 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, 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: 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[79] 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.[80] 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").[81] 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).

- **D&E Agreement Cancellation: NSTAR/Cranberry Storage (ER22-214)**

On October 27, 2021, NSTAR filed a notice of cancellation of the Engineering, Design, and Procurement Agreement ("D&E Agreement") with Cranberry Point Energy Storage, LLC ("Cranberry Storage"). The D&E Agreement set forth the terms and conditions under which Cranberry Storage reimbursed NSTAR for costs associated with advancing certain design and engineering activities for upgrades that were identified in the applicable ISO-NE) studies, prior to execution of an LGIA. The D&E Agreement terminated by its terms when an

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77 *Covanta Holding Corp*., 177 FERC ¶ 62,031 (Oct. 18, 2021).

78 *PPL Corp. and The Narragansett Elec. Co.*, 176 FERC ¶ 61,175 (Sep. 23, 2021).

79 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").

80 *Arthur Kill Power LLC et al.*, 176 FERC ¶ 62,086 (Aug. 18, 2021).

81 *Exelon Generation Co., LLC*, 176 FERC ¶ 61,121 (Aug. 24, 2021).

LGIA was executed on October 8, 2021. An October 27, 2021 effective date was requested. Comments on this filing were due on or before November 17, 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).

- **Cost Reimbursement Agreement Cancellation: National Grid/GRS (ER22-129)**

On October 18, 2021, National Grid filed a notice of cancellation of its Cost Reimbursement Agreement with Gas Recovery Systems ("GRS"). Performance under the Agreement has been completed, all amounts due and owing have been paid in full, and a new interconnection agreement between National Grid and GRS has been accepted and is currently in effect. A December 18, 2021 effective date was requested. Comments on this filing are due on or before November 8, 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).

- **CL&P/EIP E&P Agreement (ER21-2880)**

On November 10, 2021, the FERC accepted an Engineering, Design & Procurement Agreement ("E&P Agreement") between CL&P and EIP Investments, LLC ("EIP").[82] 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. The Agreement was accepted effective as of September 14, 2021, as requested. Unless the November 10 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **IA Termination: CL&P / Sterling Property (ER21-2860)**

On November 8, 2021, the FERC rejected the notice of termination filed by CL&P of a 2002 Interconnection Agreement ("IA") governing interconnection service to what CL&P characterized as a since-decommissioned 26 MW waste-tire fueled generator located in Sterling, Connecticut (the "Facility").[83] In rejecting the notice, the FERC found that CL&P had "not provided adequate justification demonstrating that the Facility has been decommissioned in order to terminate the Interconnection Agreement."[84] However, the FERC noted that its determination did not indicate that Sterling retains any interconnection rights under the IA, stating that there had been no interconnection rights associated with the facility since ISO-NE deemed the Facility retired in 2017. Unless the *Sterling IA 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. Subsequently, on November 1, 2021, Versant submitted amendments to its July 23 compliance filing to include revised and new WEQ standards identified in the Order 676-I Errata Notice but not included in the July 23, 2021 filing. Comments on the amendment filing were due on or before December 1, 2021; none were filed. This matter is again pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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[82] *The Connecticut Light and Power Co*., Docket No. ER21-2880 (Nov. 10, 2021) (unpublished letter order).

[83] *The Connecticut Light and Power Co.*, 177 FERC ¶ 61,083 (Nov. 8, 2021) ("*Sterling IA Order*").

[84] *Id*. at P 23.

- ***Orders 864/864-A* (Public Util. Trans. ADIT Rate Changes): *New England Compliance Filings* (various)**

In accordance with *Order 864*[85] and *Order 864-A*,[86] 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<br>Apr 16, 2021 | ER21-311<br>ER21-1694 | Green Mountain Power | pending<br>pending |
| Aug 5, 2020 | ER20-2614 | New England Power AC Support Agreement | pending |
| Aug 5, 2020 | ER20-2610 | CL&P | pending |
| Aug 5, 2020<br><br>Mar 8, 2021 | ER20-2609<br>ER21-1650<br>ER21-1293 | NSTAR | pending<br>pending<br>pending |
| Aug 5, 2020 | ER20-2608 | PSNH | pending |
| Aug 4, 2020 | ER20-2607 | NEP – Seabrook Transmission Support Agreement | pending |
| Jul 31, 2020 | ER20-2594<br>ER21-1709 | VTransco | pending<br>pending |
| Jul 30, 2020 | ER20-2572<br>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<br>ER21-1702 | CMP | pending<br>pending |
| Jun 29, 2020 | ER20-2219 | New England Power | pending |
| Jun 23, 2020<br>Mar 22, 2021 | ER20-2133<br>-001, -002 | Versant Power | pending |
| May 18, 2020<br>Jan 7, 2021 | ER20-1839 | VETCO | pending |
| Feb 26, 2020<br>Dec 11, 2020 | ER20-1089 | New England Elec. Trans. Corp. | pending |
| Feb 26, 2020<br>Dec 11, 2020 | ER20-1088 | New England Hydro Trans. Elec. Co. | pending |
| Feb 26, 2020<br>Dec 11, 2020 | ER20-1087 | New England Hydro Trans. Corp. | pending |

Since the last Report, *Order 864*-related activity included:

[85] *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.

[86] *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*").

♦ ***ER21-1295 (CL&P)***. On December 1, 2021, CL&P proposed limited revisions to its *Order 864* compliance filing, including: (i) a revised Permanent ADIT Worksheet and Re-measurement Support Worksheet; (ii); minor revisions to Schedule 21-CL&P; (iii) additional support for CL&P's proposed amortization periods for excess or deficient ADIT; and (iv) a delay in the amortization of excess ADIT until after the FERC has approved both regional and local *Order 864* compliance filings. Comments are due on or before December 22, 2021.

♦ ***ER21-1293 (NSTAR)***. On November 24, 2021, NSTAR proposed limited revisions to its *Order 864* compliance filing, including: (i) a revised Permanent ADIT Worksheet and Re-measurement Support Worksheet; (ii); minor revisions to Schedule 21-NSTAR; (iii) additional support for NSTAR's proposed amortization periods for excess or deficient ADIT; and (iv) a delay in the amortization of excess ADIT until after the FERC has approved both regional and local *Order 864* compliance filings. Comments are due on or before December 6, 2021.

♦ ***ER20-2429 (CMP)***. As previously reported, the FERC issued a second deficiency letter on September 15, 2021. Following two extensions granted at CMP's request (including an October 19 request), CMP's responses to the second deficiency letter were due and filed November 8, 2021.

♦ ***ER20-2133-002 (Versant)***. On November 22, 2021, Versant submitted a joint offer of settlement between itself and the MPUC to resolve all issues raised by the MPUC in response to Versant's *Order 864* compliance filings. Comments on the Offer of Settlement must be filed on or before December 13, 2021; Reply Comments, on or before December 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").[87] 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."[88] On July 19, 2021, NARUC nominated the 10 state 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 (November 10, 2021) 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 on or before September 10, 2021 comments in this docket on agenda topics for the first public meeting).[89] Comments on the

[87] *Joint Federal-State Task Force on Electric Transmission*, 175 FERC ¶ 61,224 (June 18, 2021).

[88] 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 transmission investment is cost effective, including approaches to enhance transparency and improve oversight of transmission investment including, potentially, through enhanced federal-state coordination.

[89] *Joint Federal-State Task Force on Electric Transmission*, 176 FERC ¶ 61,131 (Aug. 30, 2021).

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.

The Joint Federal-State Task Force convened for its first meeting on November 10, 2021. On November 22, 2021, the FERC issued a notice inviting comments on issues raised during the meeting, directing comments be submitted on or before December 22, 2021.

- **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. On October 14, Entergy answered the comments submitted by City of New Orleans. This matter is pending before the FERC.

- **Electrification and the Grid of the Future: Apr 29 Technical Conference (AD21-12)**

The FERC convened a Commissioner-led technical conference on April 29, 2021 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 as electrification advances. A transcript of the technical conference is posted in eLibrary. On May 17, the FERC issued a notice inviting the submission of post-technical conference comments, on or before July 1, 2021. 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. 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. A transcript of the September 30 technical conference was posted in eLibrary on November 16, 2021.

- **Modernizing Electricity Market Design - Resource Adequacy (AD21-10)**

***March 23 Tech Conf (PJM)***. The FERC convened a Commissioner-led technical conference 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)**

***Tech Conf I (Sep 14)***. On September 14, 2021, the FERC held the first of two staff-led technical conferences addressing ISO/RTO energy and ancillary services markets (including 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 an August 17, 2021 supplemental notice 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. A transcript of the September 14 technical conference was posted in eLibrary on October 14, 2021.

***Tech Conf II (Oct 12).*** A second full-day technical conference was convened on October 12, 2021. An October 7 supplemental notice identified the speakers and 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. A transcript of the October 12 technical conference was posted in eLibrary on November 22, 2021.

***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 (which it has done – *see* below), 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.

The FERC held on October 7. 2021 a virtual workshop 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 was also posted on the Calendar of Events on the FERC's website, www.ferc.gov.

On October 12, 2021, FERC Chairman Glick announced that Elin Katz, the former head of the Connecticut Office of Consumer Counsel ("CT OCC") and president of the National Association of State Utility Consumer Advocates ("NASUCA"), will lead OPP. Ms. Katz assumed her role as the Director of OPP in late November.

Since the last Report, an additional 8 sets of comments were filed by individual New England (New Hampshire) ratepayers requesting OPP's assistance and support on New England issues, including FCM Market reforms, the shutdown of Merrimack Station, and requiring "ISO New England make their plan for grid transition transparent to the community." Also, on November 9, PNNL filed a brief memo summarizing opportunities related to technical assistance and submitting all workshop documentation into the FERC record.

- **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.[90]

***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

[90] Public comments were initially due Aug. 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 Sep. 20, 2021, to file comments in response to the ISO/RTO reports.

Resource Coalition, NRECA, Pine Gate Renewables, PJM IMM, and UCS. On October 20, 2021, NYISO submitted comments in response to issues raised by those comments. 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")[91] 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.

Pre-technical conference comments were submitted by over 175 parties, including by: NEPOOL, ISO-NE, AEE, Anbaric, Avangrid, BP, CPV, Dominion, EDF, EDP, Enel, EPSA, Eversource, Exelon, LS Power, MA AG, MMWEC, National Grid, NECOS, NESCOE, NextEra, NRDC, Orsted, Shell, UCS, VELCO, Vistra, Potomac Economics, ACORE, ACPA/ESA, APPA, EEI, ELCON, Industrial Customer Orgs, LPPC, MA DOER, NARUC, NASUCA, NASEO, NERC, NRECA, SEIA, State Agencies, TAPS, WIRES, Harvard Electric Law Initiative; NYU Institute for Policy Integrity, New England for Offshore Wind Coalition, and the R Street Institute.

Reply comments were due on or before ***November 30, 2021*** and were filed by over 90 parties, including: by: CT AG, Acadia Center/CLF, CT AG, Dominion, Enel, Eversource, LS Power, MA AG, MMWEC, NESCOE, NextEra, Shell, UCS, Vistra, ACPA/ESA, AEE, APPA, EEI, ELCON, Environmental and Renewable Energy Advocates, EPSA, Harvard ELI, NRECA, Potomac Economics, and SEIA.

***November 15, 2021 Tech Conf***. On November 15, 2021, the FERC convened a technical conference 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 examined 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. Speaker materials were posted to eLibrary on November 16, 2021. On November 17, the FERC invited post-technical conference comments to be submitted on or before November 30, 2021.

- **NOI: Removing the DR Opt-Out in ISO/RTO Markets (RM21-14)**

On March 18, 2021, the FERC issued a NOI[92] 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.

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[91] *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*").

[92] *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*").

- **NOPR: Cybersecurity Incentives (RM21-3)**

On December 17, 2020, the FERC issued a NOPR[93] 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.,[94] 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[95] 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[96] 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.[97] Comments were submitted by over 50 parties, including by ISO-NE, DC Energy, Dominion, EDF, ENEL/EnerNOC, Eversource, Exelon, NRDC, Vistra, EEI, EPRI, EPSA, New England State Agencies,[98] 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,[99] the FERC issued on April 15, 2021 a *Supplemental NOPR*[100] 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

93 *Cybersecurity Incentives*, 173 FERC ¶ 61,240 (Dec. 17, 2020) ("*Cybersecurity Incentives NOPR*").

94 These joint comments were filed by aDolus Inc., Fortress Information Security, GMO GlobalSign Inc., Ion Channel, ReFirm Labs and Reliable Energy Analytics LLC.

95 The *Cybersecurity Incentives NOPR* was published in the *Fed. Reg.* on Feb. 5, 2021 (Vol. 86, No. 23) pp. 8,309-8,325.

96 *Managing Transmission Line Ratings*, 173 FERC ¶ 61,165 (Nov. 19, 2020) ("*Managing Transmission Line Ratings NOPR*").

97 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.

98 "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.

99 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.

100 *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*, 175 FERC ¶ 61,035 (Apr. 15, 2021) ("*Supplemental NOPR*").

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*.[101] 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.[102] Since the last Report, reply comments were posted from New England State Parties,[103] 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[104] 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. On October 13, 2021, the FERC posted a transcript of the workshop in eLibrary.

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[101] 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 and 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 seeks 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.

[102] "Public Interest Groups" are NRDC, Sierra Club, Sustainable FERC Project, and Western Grid Group.

[103] "New England State Parties" are CT PURA, CT DEEP and the MA AG.

[104] 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).

***Notice Inviting Post-Workshop Comments***. On October 18, 2021, the FERC issued a notice inviting those interested to file post-workshop comments to address the issues raised during the workshop concerning incentives and shared savings. Comments must be submitted on or before ***January 14, 2022***.

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

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

As previously reported, *Order 860,*[105] issued three years after the FERC's *Data Collection NOPR,*[106] (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,[107] 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,[108] 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.

***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.[109] 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

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[105] *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).

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

[107] 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.

[108] *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*").

[109] *Data Collection for Analytics and Surveillance and Market-Based Rate Purposes*, 174 FERC ¶ 61,214 (Mar. 18, 2021).

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,[110] 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 October 22, 2021, the FERC issued a second notice extending the effective and associated implementation dates of *Order 860* by an additional *three* months. The deadline for baseline submissions will be February 1, 2022. First change in status filings under these new timelines will be due March 3, 2022; second change in status filings, April 29, 2022.

***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.[111] 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,[112] 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.[113] 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.

- **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.[114] 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.

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110 The Notice was published *Fed. Reg.* on Apr. 6, 2021 (Vol. 86, No. 64) pp. 17,823-17,828.

111 *Data Collection for Analytics and Surveillance and Market-Based Rate Purposes*, 176 FERC ¶ 61,109 (Aug. 19, 2021).

112 *Standards for Business Practices and Communication Protocols for Public Utilities*, Order No. 676-J, 175 FERC ¶ 61,139 (May 20, 2021) ("*Order 676-J*").

113 *Order 676-J* was published *Fed. Reg.* on June 2, 2021 (Vol. 86, No. 104) pp. 29,491-29,503.

114 *Waiver of Tariff Requirements*, 171 FERC ¶ 61,156 (May 21, 2020) ("*Proposed Policy Statement*").

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[115] 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 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).

[115] 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.

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,[116] 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,[117] 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,[118] 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*.[119] 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").[120] 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.[121] 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.

Complainant-Aligned Parties[122] answered the New England TO's May 10 supplemental comments. On June 15, 2020, Joint Parties[123] 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.[124] WIRES submitted supplemental comments on June 18, 2020 requesting that the FERC take further action in this proceeding to "resolve the

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[116] *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.

[117] "Indicated Generators" are Vistra, NRG, FirstLight, Cogentrix, and LS Power.

[118] "Joint Trade Associations" are AEE, AWEA, EEI, EPSA, INGAA, NGSA, NRECA and SEIA.

[119] *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*").

[120] 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.[120] 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).

[121] 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.

[122] For this purpose, "Complainant-Aligned Parties" are: Conn. Public Utilities Regulatory Authority, Conn. Office of the Attorney General, Conn. Department of Energy and Environmental Protection, Conn. Office of Consumer Counsel, Mass. Office of the Attorney General, Mass. Dept. of Public Utilities, Mass. Municipal Wholesale Electric Co., and New Hampshire Electric Cooperative.

[123] "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.

[124] "Six Cities" are the Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California.

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.[125] 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.[126] 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,[127] 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 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

125 *Certification of New Interstate Natural Gas Facilities*, 174 FERC ¶ 61,125 (Feb. 18, 2021) ("*2021 NOI*").

126 *Id.* at P 3.

127 *PacifiCorp,* 175 FERC ¶ 61,039 (Apr. 15, 2021) ("*PacifiCorp Show Cause Order*").

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 November 5, 2021, the FERC issued its order assessing civil penalties against GreenHat Energy, LLC ("GreenHat"), John Bartholomew, Kevin Ziegenhorn, and [Luan Troxel as the Executor for] the Estate of Andrew Kittell ("Kittell Estate") (collectively, "Respondents").[128] The FERC found that Respondents 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. The FERC assessed civil penalties of ***$179 million***, ***$25 million***, and ***$25 million*** against GreenHat, Bartholomew, and Ziegenhorn, respectively. The FERC ordered Respondents, including the Kittell Estate, to disgorge unjust profits of just ***over $13 million***, plus interest. Each of Respondents is jointly and severally liable for payment of that disgorgement amount.[129] As previously reported, Respondents have already exercised their right to adjudicate these allegations in federal district court,[130] and the *GreenHat Penalties Order* will not be subject to rehearing. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Powhatan Energy, HEEP Fund, CU Fund, and Chen (IN15-3)**

On October 29, 2021, the FERC approved a Stipulation and Consent Agreement between OE and Houlian Chen, HEEP Fund, Inc. and CU Fund, Inc. (collectively, the "Chen Defendants").[131] This Agreement resolves (i) the FERC's claims against the Chen Defendants for violations of its Anti-Market Manipulation Rules[132] and (ii) the FERC's lawsuit in the United States District Court for the Eastern District of Virginia to request an order affirming the *Powhatan Penalties Order*, *FERC v. Powhatan Energy Fund LLC, et al.*, No 3:15-cv-00452 (MHL) as it pertains to the Chen Defendants (Federal Court Lawsuit). The Chen Defendants agreed to pay disgorgement of $600,000, without either admitting or denying the alleged violations. The FERC directed the Chen Defendants to make the disgorgement payment within 10 days of the Effective Date of the Agreement and directed PJM to allocate the disgorged funds in its discretion for the benefit of PJM customers. The Federal Court Lawsuit, as it applies to Powhatan Energy, continues.

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128 *GreenHat Energy, LLC et al.*, 177 FERC ¶ 61,073 (Nov. 5, 2021) ("*GreenHat Penalties Order*").

129 *Id.* at P1.

130 If the penalty is unpaid within 60 days, the FERC will institute a proceeding in the appropriate district court seeking an order affirming the assessment of a civil penalty. The district court will have the authority to review *de novo* the law and facts involved and the jurisdiction to enforce, modify, or set aside, in whole or in part, the penalty assessment, subject to review by the appropriate U.S. Court of Appeals.

131 *Houlihan Chen et al.*, 177 FERC ¶ 61,076 (Oct. 29, 2021).

132 The FERC found, in *Houlian Chen, Powhatan Energy Fund, LLC, HEEP Fund, LLC, and CU Fund, Inc.*, 151 FERC ¶ 61,179 (May 29, 2015) ("*Powhatan Penalties Order*"), that Houlian "Alan" Chen, HEEP Fund, Inc., CU Fund, Inc., and Powhatan Energy Fund, LLC (together, "Powhatan Respondents") violated the FERC's Anti-Manipulation Rules by engaging in fraudulent UTC transactions in PJM's energy markets. The FERC ordered the disgorgement of profits with interest and the assessment of civil penalties as follows: Powhatan Energy Fund ($16.8 million civil penalty; $3.47 million disgorgement); CU Fund: ($10.08 million civil penalty; $1.08 million disgorgement); HEEP Fund ($1.92 million civil penalty; $173,100 disgorgement); H. Chen ($1 million civil penalty for trades executed through and on behalf of Powhatan and the Funds). OE alleged that, between June and Aug. 2010, Powhatan Respondents engaged in manipulative Up To Congestion trading in PJM, trades which amounted to wash trading, long prohibited by the FERC. Specifically, Staff alleged that the transactions were designed to falsely appear to be spread trades, as a vehicle for collecting Marginal Loss Surplus Allocation ("MLSA") payments from PJM, by placing millions of MWh of offsetting trades between the same two trading points, in the same volumes and the same hours—an intentional effort to cancel out the financial consequences from any spread between the two trading points while capturing large amounts of MLSA payments.

**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[133] 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 Application for Certificate of Public Convenience and Necessity under NGA section 7(c).[134] 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*,[135] a 159-page decision addressing arguments raised on rehearing requested of *Opinion 549.*[136] *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.[137] 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.[138]

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*.

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[133] *Rover Pipeline, LLC, and Energy Transfer Partners, L.P.,* 174 FERC ¶ 61,208 (Mar. 18, 2021) ("*Rover/ETP Show Cause Order*").

[134] 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.

[135] *BP America Inc. et al.,* Opinion No. 549-A, 173 FERC ¶ 61,239 (Dec. 17, 2020) ("*BP Penalties Allegheny Order*")

[136] *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*")).

[137] *BP Penalties Allegheny Order* at P 1.

[138] *Id*. at P 319.

- ***Total Gas & Power North America, Inc. et al. (IN12-17)***

On April 28, 2016, the FERC issued a show cause order[139] in which it directed Total Gas & Power North America, Inc. ("TGPNA") and its West Desk traders and supervisors, Therese Tran f/k/a Nguyen ("Tran") and Aaron Hall (collectively, "Respondents") to show cause why Respondents should not be found to have violated NGA Section 4A and the FERC's Anti-Manipulation Rule through a scheme to manipulate the price of natural gas at four locations in the southwest United States between June 2009 and June 2012.[140]

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.[141] On July 27, Chief Judge Cintron designated Judge Suzanne Krolikowski as the Presiding ALJ and established an extended Track III Schedule[142] for the proceeding. Judge Krolikowski scheduled and convened on August 26, 2021 a prehearing conference in this proceeding.

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. In light of the settlement judge procedures described just below, 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***. On September 21, 2021, Chief Judge Cintron concurrently designated Judge Joel deJesus as Settlement Judge to explore the possibility of settlement. Three settlement conferences were held (October 15, 25 and November 1, 2021). On November 9, 2021, Judge deJesus declared an impasse and recommended that settlement judge procedures be terminated. On November 16, 2021, Chief Judge Cintron issued an order terminating settlement judge procedures. The procedural schedule for the hearing will continue to remain in effect.

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

140 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.

141 *Total Gas & Power North America, Inc. et al.,* 176 FERC ¶ 61,026 (July 15, 2021).

142 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.
  - On October 15, 2021, Iroquois submitted a supplemental Life Cycle Greenhouse Gas Analysis Report.
  - On November 12, 2021, FERC staff issued the final EIS for the Project, which responds to comments that were received on the September 30, 2020 Environmental Assessment and June 11, 2021 draft EIS and discloses downstream GHG emissions for the Project. "With the exception of climate change impacts, FERC staff concluded that approval of the proposed Project, with the mitigation measures recommended in this EIS, would not result in significant environmental impacts."

- ***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.[143] Rehearing of the *Authorization Order* was timely requested, but denied by operation of law.

[143] *Algonquin Gas Transmission, LLC*, Docket No. CP16-9 at 1 (Sep. 24, 2020) (delegated order) ("*Authorization Order*").

- *Briefing Order*. In a fairly unprecedented order issued February 18, 2021,[144] 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, 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".[145] 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,[146] 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*.[147]
- 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:

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[144] *Algonquin Gas Transmission, LLC and Maritimes & Northeast Pipeline, LLC*, 174 FERC ¶ 61,126 (Feb. 18, 2021) ("*Briefing Order*").

[145] *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*").

[146] *Algonquin Gas Transmission, LLC and Maritimes & Northeast Pipeline, LLC*, 175 FERC ¶ 61,150 (May 19, 2021) ("*May 19 Order*").

[147] *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*").

- **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.[148] Those orders have been challenged on appeal to the US Court of Appeals for the Second Circuit (19-1610).
  - As previously reported, the August 6, 2018 *Northern Access Certificate Rehearing Order* dismissed or denied the requests for rehearing of the *Northern Access Certificate Order*.[149] 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,[150] 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.[151] 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.[152] 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.

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

[149] *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).

[150] 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).

[151] *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*").

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

- On August 8, 2019, the NY DEC again denied Applicants request for a Water Quality Certification, and as directed by the Second Circuit,[153] 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.[154]
- 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, [155] 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.[156]

## 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.

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[153] 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).

[154] *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).

[155] *National Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 173 FERC ¶ 61,197 (Dec. 1, 2020).

[156] *Id.* at P 10.

***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, 2021 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 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).

- **Mystic ROE (21-1198; 21-1222, 21-1223, 21-1224) (consolidated)**
  **Underlying FERC Proceeding: EL18-1639-010, -011[157]**
  **Petitioners: Mystic, CT Parties, MA AG, ENECOS**
  **Status: Filing of Initial Submissions Underway**

As previously reported, on October 8, 2021, Mystic petitioned the DC Circuit Court of Appeals for review of the FERC's orders setting the base ROE for the Mystic COS Agreement at 9.33%. On October 14, 2021, the Court ordered Mystic to file, and Mystic filed on October 29, a Docketing Statement Form, a Statement of Intent to Utilize Deferred Joint Appendix, a Statement of Issues to be Raised, the Underlying Decision from which the appeal arises.

Since the last Report, three additional appeals of the *Mystic ROE Orders* were filed (by CT Parties (21-1222), MA AG (12-1223), and ENECOS (21-1224)) and consolidated with Case No. 21-1198, with 21-1198 designated as the lead case. Also, as noted in Section II above, the FERC issued its *Mystic ROE Allegheny Order* (further reducing the ROE to 9.13%). The new Petitioners in this consolidated appeal were ordered to file Docketing Statement Forms and Statements of Issues to be Raised by December 15, 2021. A FERC request to delay submission of the certified index by 60 days (to allow for inclusion of all activity following the *Mystic ROE Allegheny Order*) remains pending before the Court.

- **ISO-NE Implementation of Order 1000 Exemptions for Immediate Need Reliability Projects (20-1422)**
  **Underlying FERC Proceeding: EL19-90[158]**
  **Petitioner: LS Power**
  **Status: Briefing Complete; Oral Argument Scheduled for Jan 27, 2022**

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. On November 13, 2021, the Court scheduled oral argument for

[157] *Constellation Mystic Power, LLC, 176 FERC ¶ 61,019 (July 15, 2021) ("Mystic ROE Order"); Constellation Mystic Power, LLC, 176 FERC ¶ 62,127 (Sep. 13, 2021) ("September 13 Notice") (Notice of Denial By Operation of Law of Rehearings of Mystic ROE Order).*

[158] *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).

Thursday, January 27, 2022. The composition of the argument panel will be identified roughly 30 days prior to oral argument.

- **CIP IROL Cost Recovery Rules (20-1389)**
  **Underlying FERC Proceeding: ER20-739**[159]
  **Petitioner: Cogentrix, Vistra**
  **Status: Briefing Complete; Oral Argument Held 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. Following the completion of briefing, oral argument before Judges Srinivasan, Katsas and Randolph was held on November 12, 2021. This matter is pending before the Court.

- **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**[160]
  **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.[161] 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 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**[162]
  **Petitioners: Sierra Club, NRDC, RENEW Northeast, and CLF**
  **Status: Being Held in Abeyance (until June 1, 2022)**

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

[159] *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*").

[160] *July 2018 Order*; *July 2018 Rehearing Order*; *Dec 2018 Order*; *Dec 2018 Rehearing Order; Jul 17 Compliance Order*.

[161] 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.

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

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. On October 22, 2021, Petitioners Sierra Club, NRDC, Renew Northeast, Inc., and CLF moved the Court to hold this matter in abeyance until June 1, 2022. On October 25, 2021, the Court granted Petitioners' second motion to hold this matter in abeyance. The parties were directed to file motions to govern future proceedings in these cases on or before June 1, 2022.

- ***Opinion 531-A* Compliance Filing Undo (20-1329)**
  **Underlying FERC Proceeding: ER15-414**[163]
  **Petitioners: TOs' (CMP et al.)**
  **Status: Being Held in Abeyance**

On August 28, 2020, the TOs[164] 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 FERC's orders later vacated by the DC Circuit's *Emera Maine*[165] 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

163 *ISO New England Inc.*, 161 FERC ¶ 61,031 (Oct. 6, 2017) ("*Order Rejecting Filing*").

164 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.

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

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**[166]
  **Petitioner: TransCanada**
  **Status: Briefing Complete; Oral Argument Held 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*.[167] Following completion of briefing, oral argument was held Friday, October 15, 2021 before Judges Srinivasan, Henderson and Edwards. This matter is pending before the Court.

- **ISO-NE's Inventoried Energy Program (Chapter 2B) Proposal (19-1224***; 19-1247; 19-1252; 19-1253)(consolidated); Underlying FERC Proceeding: ER19-1428**[168]
  **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 Held 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. Following completion of briefing, oral argument was held October 21, 2021 before Judges Wilkins, Katsas and Jackson. This matter is pending before the Court

### Other Federal Court Activity of Interest

- ***Order 872* (20-72788,* 21-70113; 20-73375, 21-70113) (consol.) (9th Cir.)**
  **Underlying FERC Proceeding: RM19-15**[169]
  **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*.[170] On October 9, the FERC filed an unopposed motion for the Court to hold this appeal in abeyance, suspend filing of the

[166] 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*").)

[167] 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.

[168] 162 FERC ¶ 61,127 (Feb. 15, 2018) ("*Order 841*"); 167 FERC ¶ 61,154 (May 16, 2019) ("*Order 841-A*").

[169] *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).

[170] *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

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.[171] 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. Respondent's brief was filed on September 27. The Joint brief of respondent-intervenors and motions and associated briefs by amici curiae in support of respondent were filed on October 27, 2021. Any optional reply briefs must be filed by December 13, 2021.

- **PennEast Project (18-1128)**
  **Underlying FERC Proceeding: CP15-558**[172]
  **Petitioners: NJ DEP, DE and Raritan Canal Commission, NJ Div. of Rate Counsel**
  **Status: Being Held in Abeyance**

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.

On October 29, FERC and Petitioners NJ DEP, DE and Raritan Canal Commission, NJ Conservation Foundation and The Watershed Institute, NJ Division of Rate Counsel, Township of Hopewell, NJ and ConEd (collectively, "Movants") requested that the Court suspend the supplemental briefing schedule entered on September 13, 2021 and hold this consolidated case in abeyance. The Court granted that motion on November 12, 2021 and directed the parties to file motions to govern future proceedings by February 18, 2022.

- **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**[173]
  **Petitioners: MISO TOs, Transource Energy, Dec 23 Petitioners et al.**
  **Status: Oral Argument Held Nov 18**

The MISO Transmission Owners (TOs), Transource and "Dec 23 Petitioners",[174] 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. Following completion of briefing, oral

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.

171 "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.

172 *PennEast Pipeline Co., LLC*, 162 FERC ¶ 61,053 (Jan. 19, 2018), *reh'g denied*, 163 FERC ¶ 61,159 (May 30, 2018).

173 *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).

174 "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.

argument was held on November 18, 2021 before Judges Srinivasan, Katsas and Walker. This matter is pending before the Court.

- **Algonquin Atlantic Bridge Project Briefing Order (21-1115*, 21-1138, 21-1153, 21-1155) (consol.); Underlying FERC Proceeding: CP16-9-012[175]**
  **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.” The Court granted the first abeyance motion. On November 15, 2021, the Court granted a third abeyance motion by the FERC, directing the parties to file motions to govern future proceedings by January 31, 2022.

[175] *Briefing Order*; *April 19 Notice of Denial of Rehearings by Operation of Law*

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