NEW ENGLAND POWER POOL
David T. Doot
Secretary

October 29, 2020

VIA ELECTRONIC MAIL

TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

RE: Supplemental Notice of November 5, 2020 NEPOOL Participants Committee Teleconference Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that the November meeting of the Participants Committee will be held **via teleconference on *Thursday*, November 5, 2020, at 10:00 a.m.** for the purposes set forth on the attached agenda and posted with the meeting materials at http://nepool.com/NPC_2020.php. The dial-in number, to be used only by those who otherwise attend NEPOOL meetings, is **866-803-2146; Passcode: 7169224.**

For your information, the November 5 meeting will be recorded, as are all the NEPOOL Participants Committee meetings. NEPOOL meetings, while not public, are open to all NEPOOL Participants, their authorized representatives and, except as otherwise limited for discussions in executive session, consumer advocates that are not members, federal and state officials and guests whose attendance has been cleared with the Committee Chair. All those in attendance or participating in the meeting are required to identify themselves and their affiliation during the meeting. Official records and minutes of meetings are posted publicly. No statements made in NEPOOL meetings are to be quoted or published publicly.

We do not expect Agenda Item 9 on potential future market pathways will begin before 12:15 p.m. For planning purposes, those participating in that portion of the meeting should be prepared for Agenda Item 9 to take as much as three to four hours for presentations and questions and answers. Note that the WebEx link for Agenda Item 9 is different than the link you will use for the earlier items on the agenda, so you will need to join the WebEx event at the beginning of Agenda Item 9.

Please note that the Sector meetings with the ISO Board panels will take place on Friday, November 6. Many of the Sector meetings with New England State representatives have been scheduled for later in November and early December. A schedule for those 75-minute meetings is also included with these materials and you will receive separately the details for you to join your Sector meetings. Please be sure to save those dates on times on your calendars.

We hope all of you are staying safe and healthy.

Respectfully yours,

/s/

David T. Doot, Secretary

FINAL AGENDA

1. To approve the draft minutes of the October 1, 2020 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 all actions recommended by the Technical Committees set forth on the Consent Agenda included with this initial notice and posted with the meeting materials.

3. To receive an ISO Chief Executive Officer report.

4. To receive an ISO Chief Operating Officer report.

5. To consider and take action, as appropriate, on proposed "Know Your Customer Changes" revisions to the Financial Assurance Policy. Background materials and a draft resolution are included and posted with this supplemental notice

6. To consider and take action, as appropriate, on ISO-NE-proposed revisions to sections III.13.1.2.3.1(A) and III.13.2.3.2 (a)(v) of Market Rule 1 for recalculating the Dynamic De-List Bid Threshold using updated data for FCA 16. Background materials and a draft resolution are included and posted with the supplemental notice.

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

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

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

9. Pathways to New England's Future Grid. The following presentations and discussions are planned:

    Dr. Frank Felder, continuation of discussion on various questions and tradeoffs associated with potential future pathways explored to date (i.e., the pros and cons of each pathway). Dr. Felder's presentation will be circulated and posted in advance of the meeting.

    Dr. Frank Wolak, discussion of an additional potential market framework for New England in light of expected changes to the grid. A white paper authored by Dr. Wolak is included and posted with this supplemental notice. Dr. Wolak's presentation will be circulated and posted in advance of the meeting.

    Also included for your information with this Supplemental Notice (and posted to the NEPOOL website) are two separate written submissions provided by certain NEPOOL members regarding potential future pathways.

10. Administrative matters.

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

Electronic Participation Guidelines
General Session Part I – November 5, 2020 Participants Committee Teleconference

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, 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.

BEFORE THE MEETING

- **Download Materials** from the NEPOOL or ISO-NE websites. Will minimize disruptions from WebEx or internet service interruptions

PROXIES

- If unable to participate for any portion of the general session, members and alternates are encouraged to designate a temporary alternate or proxy by e-mail to pmgerity@daypitney.com.

JOIN THE TELECONFERENCE
866-803-2146; 7169224#

- 866-803-2146; access code 7169224#.
- Slowly state your name and the Participant you are representing, followed by the # key.
- Audio by phone only. No computer-based audio available.

Join Meeting

JOIN THE WEBEX MEETING
WebEx Link

- Click <Classic View> on right side of menu. Do not use <Modern View>.
- Enter first name, last name and e-mail address.
- Enter meeting password: **nepool.**
- Click <Join>. Video will be disabled.

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DURING GENERAL SESSION

- **MUTE YOUR PHONE** (*6) when not speaking.
- **DO NOT PLACE THE CALL ON HOLD** – if taking another call, hang-up and rejoin when ready.
- **USE A HANDSET** when speaking. Use of headsets/speaker phones strongly discouraged.
- **ASK AND WAIT** to be recognized by the Chair.
- **IDENTIFY** yourself/your Participant once recognized and before continuing.

VOTING

- Voice Votes. Oppositions and Abstentions will be noted for the record.
- Roll Call Votes. Will be taken if and as (i) necessary or (ii) requested by any member.

SERVICE INTERRUPTIONS

- Report dropped calls by e-mail to the Chair or Secretary.
- If teleconference system has failed, stand by on e-mail for updates via NPC distribution list.
- PATIENCE. We thank you for your patience during these unprecedented times of remote workforce deployment and strain on teleconference and WebEx services.

Stay Safe and Healthy

Electronic Participation Guidelines
General Session Part II – November 5, 2020 Participants Committee (WebEx Event)

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, 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.

BEFORE THE MEETING

- **Download event materials** from the NEPOOL or ISO-NE websites**.** Will minimize disruptions from WebEx or internet service interruptions.

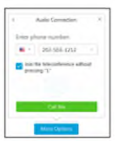
JOIN THE WEBEX EVENT

Join Event

[WebEx Link]

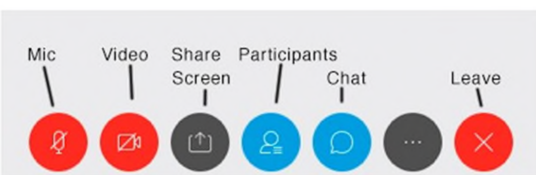
- Click <Classic View> on right side of menu. Do not use <Modern View>. Use **WebEx Events** Tab.
- Enter first name, last name and e-mail address.
- Enter event password: **nepool.**
- Click <Join>.

CONNECT TO WEBEX AUDIO



- **Call Me** - Enter a phone number, select **Call Me** (encouraged) and WebEx calls you.
- **Call Using Computer** – choose this option to connect to audio using VoIP. Use of headset when using VoIP strongly encouraged.
- **Call In** – If you prefer to use your phone for audio, dial the phone number shown on your screen. When prompted, use your phone keypad to enter the access code, and the Attendee ID shown on your screen. Choose this option if your Internet connection is slow. **Turn off sound from your computer to avoid feedback**.

DURING THE MEETING



- **TURN OFF YOUR VIDEO** – Choose Active Speaker View. Only Presenters should be seen on video.

- **MUTE YOUR MIC OR PHONE** when not speaking.
- **ASK AND WAIT** to be recognized by the Chair.
- **IDENTIFY** yourself/your Participant once recognized and before continuing.

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NEPOOL PARTICIPANTS COMMITTEE
NOVEMBER / DECEMBER 2020 SECTOR/GROUP MEETING SCHEDULE**
v. 2020.10.30

SECTOR/GROUP	ISO Board Panel 1	ISO Board Panel 2	State Officials
Generation / Long	Fri, Nov 6 10:30 – 11:45 am		Fri, Dec 11 3:00 - 4:15 pm
Transmission		Fri, Nov 6 10:30 – 11:45 am	Fri, Nov 13 1:45 - 3:00 pm
Supplier / Short (LSE)		Fri, Nov 6 1:00 – 2:15 pm	Mon, Nov 16 1:30 - 2:45 pm
Publicly Owned Entity		Fri, Nov 6 3:00 – 4:15 pm	Fri, Nov 20 11:00 - 12:15 pm
AR	Fri, Nov 6 1:00 – 2:15 pm		Mon, Dec 7 11:45 - 1:00 pm
End User	Fri, Nov 6 3:00 – 4:15 pm		Fri, Dec 11 1:15 - 2:30 pm

ISO Board Panel 1: Kathleen Abernathy, Roberto Denis, Barney Rush, Mark Vannoy, and Vickie VanZandt.

ISO Board Panel 2: Brook Colangelo, Mike Curran, Cheryl LaFleur, Philip Shapiro, and Gordon van Welie.

State Officials: [TBD].

**** Subject to change**

PRELIMINARY

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held via teleconference, beginning in executive session at 9:00 a.m. on Thursday, October 1, 2020. A quorum determined in accordance with the Second Restated NEPOOL Agreement was present and acting throughout the meeting. Attachment 1 identifies the members, alternates and temporary alternates who participated in the teleconference meeting.

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

EXECUTIVE SESSION

The Committee began the meeting in executive session to consider two confidential items - the extension and amendment of the GIS Administration Agreement and to ratify consulting arrangements entered into in connection with ongoing efforts on the Future Grid Initiative.

EXTENSION AND AMENDMENT OF GIS ADMINISTRATION AGREEMENT

Following discussion in executive session, the Committee considered and unanimously approved the following motion:

> RESOLVED, that the Participants Committee approves the Extension of and First Amendment to the Amended and Restated Generation Information System Administration Agreement between NEPOOL and APX, Inc., as circulated to the Committee and discussed at this meeting, together with any non-substantive changes as the Chairman of the GIS Agreement Working Group may approve.

RATIFICATION OF CONSULTING ARRANGEMENTS

The Committee then considered, discussed in executive session and unanimously approved in a single vote the following motions:

> RESOLVED, that the NEPOOL Participants Committee ratifies, to the extent required, (a) the agreement of the Participants Committee officers to retain the services of Peter G. Flynn as a project administrator to perform the scope of services described

> more fully in the confidential document circulated in advance of the meeting entitled "Future Grid Study, Project Administrator – Scope, Tasks, Deliverables, Governance and Budget" (the Scope), and (b) the execution and delivery by the Chair or any Vice-Chair of this Committee of an agreement among the parties to that arrangement reflecting that Scope (together with such non-substantive changes as may be approved by the parties), in final form acceptable to the parties, and any other related agreements and documents as they may deem necessary or desirable.

> RESOLVED, that the NEPOOL Participants Committee ratifies, to the extent required, (a) the agreement of the Participants Committee officers to retain the services of Dr. Frank Felder to perform the scope of services described more fully in the confidential document circulated in advance of the meeting entitled "Transition to the Future Grid--Facilitation of NEPOOL Discussions of Potential Future Pathways for New England--Proposed Outline of Consulting Engagement -- September through December 2020" (the Scope), and (b) the execution and delivery by the Chair or any Vice-Chair of this Committee of an agreement between the parties to that arrangement reflecting that Scope (together with such non-substantive changes as may be approved by the parties), in final form acceptable to the parties, and any other related agreements and documents as they may deem necessary or desirable.

GENERAL SESSION

Following a short recess, the NEPOOL Participants Committee reconvened, beginning at 10:00 a.m. A quorum determined in accordance with the Second Restated NEPOOL Agreement was reconfirmed. Those members, alternates and temporary alternates who participated in both the executive and general session portions of the meeting are identified in ***bold italics*** in the Attachment 1 attendance list.

Ms. Chafetz began the general session by acknowledging the passing on September 25, 2020 of Mr. Eugene Litvinov, the ISO's chief technologist. She noted that Mr. Litvinov was known as the "genius behind the scenes" and, with legendary brilliance, had left his mark on virtually every aspect of the New England Markets. On behalf of NEPOOL and the NEPOOL

Participants, she extended sincere condolences to his family and to colleagues at the ISO, noting that Eugene would be sorely missed. In tribute, a moment of silence was observed.

APPROVAL OF SEPTEMBER 3, 2020 MEETING MINUTES

Ms. Chafetz then referred the Committee to the preliminary minutes of the September 3, 2020 meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of the September 3, 2020 meeting were unanimously approved as circulated, with an abstention by Mr. Michael Kuser's alternate, Mr. Jason York, noted.

REVISIONS TO OP-17 AND OP-21

Ms. Chafetz referred the Committee to revisions to Operating Procedure (OP) 17 (Load Power Factor and System Assessment), including changes to Appendices B and C (collectively, OP-17) and to OP-21 (Operational Surveys, Energy Forecasting & Reporting and Actions During An Energy Emergency), each as unanimously recommended by the Reliability Committee (RC) at its September 23, 2020 meeting and described in materials circulated in advance of the Participants Committee meeting. She said that the revisions to OP-17 and OP-21 would have been on the Consent Agenda but for the timing of the RC's consideration and vote.

The following motions were duly made, seconded, and unanimously approved in a single vote without comment, with an abstention noted by Mr. Kuser's alternate, Mr. York:

> RESOLVED, that the Participants Committee supports the revisions to OP-17 (including changes to Appendices B & C), as recommended by the Reliability Committee, and as reflected in the materials distributed to the Participants Committee for its October 1, 2020 meeting, together with such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee.

> RESOLVED, that the Participants Committee supports the revisions to OP-21, as recommended by the Reliability Committee, and as reflected in the materials distributed to the Participants Committee for its October 1, 2020

meeting, together with such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee.

ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), referred the Committee to the summaries of the ISO Board and Board Committee meetings that had occurred since the September 3, 2020 meeting, which had been circulated and posted in advance of the meeting. He reported that, at its annual meeting on September 17, the ISO Board had elected Messrs. Brook Colangelo, Roberto Denis and Mark Vannoy as Directors for three-year terms, had elected Ms. Kathleen Abernathy as Chair, and had adopted the committee assignments identified in the summary. He also noted that, as stated in his comments for the FERC's technical conference on carbon pricing convened the day before, and as he would explain more fully later in the meeting, the Board had directed the ISO to prioritize analysis of two pathways under discussion in NEPOOL's "Pathways to the Future Grid" initiative -- net carbon pricing and a forward clean energy market (FCEM). He said that the Board wished to hear directly from stakeholders on those and the other various pathways under discussion when it meets with Sectors and NECPUC/NESCOE in November. He encouraged that the request to discuss the various pathways be taken into consideration as materials are prepared for those meetings. Mr. van Welie invited questions regarding the summaries. There were no questions or comments on those summaries.

ISO COO REPORT

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), referred the Committee to his October report, which had been circulated and posted in advance of the meeting. He noted that the data in the report was through September 23. The report highlighted: (i) Energy Market value for September 2020 was $158 million, down $148 million from August 2020 and down

$53 million from September 2019; (ii) August 2020 average natural gas prices were 1.3 percent lower than August average values; (iii) the average Real-Time Hub Locational Marginal Prices (LMP) for August ($20.47/MWh) were 14 percent lower than August averages; (iv) average August 2020 natural gas prices and Real-Time Hub LMPs over the period were down 25 percent and up 0.1 percent, respectively, from September 2019; (v) the average Day-Ahead cleared physical energy during peak hours as percent of forecasted load was 99.3 percent during September (down from 101.4 percent during August), with the minimum value for the month (93.6 percent) on September 16; and (vi) the Daily Net Commitment Period Compensation (NCPC) payments for August totaled $1.9 million, which was down $1.5 million from August 2020 and down $0.4 million from September 2019. September NCPC, which was 1.2 percent of total Energy Market value, was comprised of (a) $1.4 million in first contingency payments (down $900,000 from August); (b) $237,000 in second contingency payments (down $601,000 from August); (c) $~~262000~~262,000 in voltage payments (up from $4,000 in August); and (d) $6,000 in distribution payments (down $199,000 from August).

Dr. Chadalavada responded to questions received following circulation and posting of the October report regarding load forecast performance on September 8, second contingency commitments during September, and posturing during a few days in the first part of that month. With respect to load forecast performance on September 8, he reported that loads exceeded forecast levels by more than nine percent (19,000 MW actual versus 17,400 MW forecast). He attributed the underforecast to hotter than expected weather, which increased air conditioning load, and the inability of modeling to predict the impact of the first day back in school during the ongoing pandemic. There were binding constraints in total Ten-Minute Spinning Reserve, total Thirty-Minute Operating Reserve and Ten-Minute Non-Spinning Reserve Requirements. Those constraints, he said, resulted in the out-of-market commitment and dispatch of fast-start internal combustion units and, ultimately, $~~500,00~~500,000 in first contingency uplift payments. He said the ISO was working to refine ~~the~~its modeling based on the experience.

Dr. Chadalavada then explained that second contingency commitments during the month of September resulted from a two-day planned outage of line 391 in Maine, which cost $100,000, and, from a few days in the latter part of September (21-23), in which two planned transmission outages (of Line 343 and the Phase II line), together with heavy exports to New Brunswick, led to insufficient resources clearing in the Day-Ahead Energy Market in the eastern part of the Maine Load Zone.

He also explained that posturing on September 8-10 occurred because the available water to power a pumped storage unit had been depleted to less than one hours' worth of energy. That posturing, he said, was in accordance with long-standing procedures -- often used a few days a month -- to protect against or prepare for a response to a NERC Disturbance Control Standard violation (which requires area control error (ACE) to be within or returned to a specified range).

Dr. Chadalavada concluded his report by noting that, from October 19 to November 10, line 393-312 would be out of service for a planned outage, which would for that period of time reduce the transfer limits (import and export) between New York and New England to 600 MW.

2021 WORK PLAN

Dr. Chadalavada then referred the Committee to, and provided a summary of, the presentation, circulated and posted in advance of the meeting, identifying objectives and highlights of the 2021 Work Plan. He noted initiatives focused on innovation for the clean-energy transition across markets, planning, operations, and software structures. Those initiatives included Energy Security Initiatives (ESI)-related projects (market power assessment mitigation framework, seasonal ~~forward reserve market~~Forward Reserve Market and conforming changes), the Future Grid Initiative, transmission planning for an evolving grid (initiated at the Planning

Advisory Committee (PAC) in September), an evaluation of the impacts of shifting net peak loads (and effective load carrying capability (ELCC)), and efforts to be required to respond to the FERC's recent Order 2222 (the rulemaking order facilitating participation of distributed energy resource (DER) aggregations in ISO/RTO markets). Additional priorities for 2021 would include reviewing lessons learned from the first competitive transmission solicitation process, continuing improvements to operational and long-term planning forecasts, including consideration of COVID-19 impacts and other data-related enhancements, and moving the financial assurance for and settling of the Financial Transmission Rights (FTR) market to a clearinghouse. He noted plans to further enhance cybersecurity protections and implement upgrades to the nGEM Day-Ahead Market clearing software to improve system speed and efficiency. Dr. Chadalavada acknowledged the ongoing impacts and challenges presented by COVID-19, but committed the ISO to work collaboratively to complete the initiatives and projects in an effective and efficient manner.

Following his presentation, members expressed appreciation to the ISO for its efforts and responsiveness, both with respect to load forecasting and development of net ICR, particularly given impacts of COVD-19, as well as for its efforts to address financial assurance and settlement-related issues associated with long-term FTRs.

In response to questions, Dr. Chadalavada clarified that initial efforts were underway on a Market Power Assessment to identify the extent to which market power could be exercised with ESI Day-Ahead Ancillary Services. He explained that such an assessment could not be completed until after the FERC's order on ESI and consideration of any changes to the proposed design that might be required. The ISO currently planned, particularly given concerns raised in the ESI proceeding, to dedicate significant resources to the project so that the Market Power Assessment could be completed and filed in 2021. By contrast, the study and potential implementation or incorporation into the region's market design and systems of ELCC was likely to take a number of years to work through with stakeholders, with efforts continuing throughout 2021 and into 2022. He confirmed that the ISO still planned to meet its commitment previously made in April to look at, for FCA16, supply side adjustments for Energy Efficiency and the impacts of the current and projected shift in net peak load. Dr. Chadalavada also re-confirmed that the ISO remained committed to a seasonal forward market, though how work would progress in 2021 and beyond was not yet certain.

2021 ISO AND NESCOE BUDGETS

Ms. Michelle Gardner, Budget & Finance Subcommittee (B&F) Chair, referred the Committee to the materials circulated and posted in advance of the meeting related to the proposed 2021 ISO Capital and Operating Budgets and the 2021 NESCOE Budget. She described the review process followed to that point and that, with the benefit of those detailed reviews with NEPOOL, no member had raised any material concerns or objections with any of the Budgets in the NEPOOL process. She referred members to the questions and comments of certain New England state regulators and consumer advocates on the ISO Budgets, and the ISO responses, all of which had been posted. She also noted a change in NESCOE's presentation to the proposed Schedule V rate to reflect updated 2021 Network Load Factor information.

Without objection, and following two motions were duly made, seconded and unanimously approved together in a single vote, with an abstention noted by Mr. Kuser's Alternate:

> RESOLVED, that the Participants Committee supports the Year **2021 ISO operating budget and capital budget** proposed by the ISO, as presented at this meeting.

> RESOLVED, that the Participants Committee supports the Year **2021 NESCOE budget**, as proposed by NESCOE at this meeting, as the Year 2021 operating budget for NESCOE.

HQICC AND ICR VALUES FOR 2024-25 (FCA15) CAPACITY COMMITMENT PERIOD

Ms. Emily Laine, Reliability Committee Chair, referred the Committee to materials circulated in advance of the meeting concerning the Hydro-Québec Interconnection Capability Credits (HQICC) Values and the Installed Capacity Requirement (ICR) values and the related demand curves (collectively, the ICR Values) to be used for the 2024-25 Capacity Commitment Period associated with FCA15. She reported that, following development by the ISO in consultation with the Power Supply Planning Committee, the Reliability Committee recommended at its September 23 meeting Participants Committee support for both the HQICC Values and the ICR Values.

HQICC Values

The following motion was duly made and seconded:

> RESOLVED, that the Participants Committee supports the ***FCA15 HQICC Values***, as recommended by the Reliability Committee and as reflected in the materials distributed to the Participants Committee for its October 1, 2020 meeting, together with such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee.

The CSC representative stated CSC would oppose resolutions being voted on both the HQICCs and the ICR Values because the calculations failed to take into account the reliability benefits of the Cross-Sound Cable. The LIPA representative echoed CSC's comments and indicated LIPA would similarly oppose both resolutions. The Calpine representative stated Calpine would abstain on the HQICC motion, given Calpine's previously-articulated objection to the reliance by the region on non-capacity-backed tie benefits to satisfy regional capacity requirements.

The Committee considered and approved the motion on HQICCs, with opposition noted by CSC and LIPA, and abstentions noted by Acadia Center, BP, Calpine, CLF, DTE, Environmental Defense Fund, Exelon, MA AG, Mercuria, Michael Kuser, NRDC, Priogen, and the AR Sector Small RG Group Member.

ICR Values

The following motion was then duly made and seconded:

> RESOLVED, that the Participants Committee supports the ***FCA15 ICR Values***, as proposed by the ISO and recommended by the Reliability Committee and as reflected in the materials distributed to the Participants Committee for its October 1, 2020 meeting, together with such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee

Without further discussion, the Committee approved the motion on the ICR Values, with opposition noted by CSC, Exelon and LIPA, and abstentions noted by Acadia Center, BP, Calpine, CLF, DTE, Environmental Defense Fund, MA AG, Mercuria, Michael Kuser, NRDC, Priogen, and the AR Sector Small RG Group Member.

ISO PROPOSAL TO EXEMPT EE FROM PFP SETTLEMENT

Ms. Chafetz referred the Committee to the materials circulated and posted in advance of the meeting regarding proposed changes to the Market Rules to exempt energy efficiency resources (EE) in the Forward Capacity Market (FCM) from Pay-for-Performance (PFP) payments/penalties (the Proposal) and changes to the Financial Assurance Policy (FAP) that would support the implementation of the Proposal. She explained that the proposed Market Rule changes would be considered and voted separately from the FAP changes. She further explained that the vote on the FAP Changes was intended to allow those who oppose the Market Rule changes to register conditional support for the related FAP changes if the Market Rule changes were to be implemented without NEPOOL support.

Proposed Market Rule Changes

Ms. Mariah Winkler, Markets Committee Chair, summarized the Market Rule changes and provided the procedural background for the Markets Committee's consideration of the changes. She reported that, at its September 8, 2020 meeting, the Markets Committee considered but did not recommend Participants Committee support for the changes, with a 55.57% Vote in favor.

The following motion was duly made and seconded:

> RESOLVED, that the Participants Committee supports the Tariff revisions to exempt energy efficiency resources from Capacity Performance Payments, as proposed by ISO New England and circulated to this Committee in advance of this meeting, together with such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

Rather than provide their detailed objections to the ISO's proposed changes, members referred to their positions articulated during the Markets Committee consideration, with some briefly summarizing those positions. An AR Sector member who opposed the Proposal explained how in his view the Proposal substantively provided the wrong incentives to EE (depriving EE of the potential for payments for reliable performance that could be used, directly or indirectly, to fund additional EE, in turn reducing the likelihood of future PFP events) and procedurally set a bad precedent (by so quickly undoing in part a piece of a comprehensive compromise reached in connection with revisions to Market Rule 1 recently filed and accepted that related to EE Capacity Supply Obligations (CSOs) during Scarcity Conditions).

A Generation Sector representative suggested that, should the Proposal be filed and approved, it would be appropriate thereafter to undertake a more comprehensive review of the treatment of other resource types that, like EE, may not be subject to Real-Time visibility, five-minute performance data, or be capable of responding to Real-Time events. Others echoed the need for a broad review, particularly given the significance of the changes and impetus for more tailored treatment of resource types.

Those supporting the changes highlighted improvements in market design and the support for the changes by the ISO Internal and External Market Monitors.

The Committee then considered and did not approve the Market Rule Changes. The motion, which required a 60% Vote to be approved by the Committee, failed to pass with a 58.35% Vote in favor (Generation Sector – 16.70%; Transmission Sector – 16.70%; Supplier Sector – 16.70%; AR Sector – 8.25%; Publicly Owned Entity Sector – 0%; and End User Sector – 0%). (See Vote 1 on Attachment 2).

Proposed Financial Assurance Policy Changes

Ms. Gardner described the FAP changes, which would support the implementation of the Proposal by excluding Capacity Supply Obligations associated with EE from the calculation of FCM Delivery Financial Assurance requirements. She reported that the B&F Subcommittee had reviewed the FAP changes at its August 3 and 21, 2020 meetings. There were no objections raised during that review.

The following motion was duly made and seconded:

> RESOLVED, that, if the Tariff revisions to exempt energy efficiency resources from Capacity Performance Payments proceed as proposed by the ISO, the Participants Committee supports revisions to Section VII.A of the ISO New England Financial Assurance Policy to exclude Capacity Supply Obligations associated with Energy Efficiency measures from the calculation of FCM Delivery Financial Assurance requirements, as circulated to this Committee in advance of this meeting, together with such non-substantive changes as may be approved by the Chair of the Budget and Finance Subcommittee.

Without discussion, the motion to support the FAP changes, which required a 66.67% Vote to be approved by the Committee, was approved with a 79.47% Vote in favor (Generation

Sector – 16.70%; Transmission Sector – 16.70%; Supplier Sector – 16.70%; AR Sector – 11%; Publicly Owned Entity Sector – 16.70%; and End User Sector – 1.67%). (See Vote 2 on Attachment 2).

In response to questions to the ISO regarding how it planned to proceed given the input received, the ISO indicated plans to file the Proposal as a package. Further, the ISO explained that, given other regulatory developments and obligations, that filing would likely be delayed until after the first of the year, with a requested effective date at least 60 days from the date of the filing. A member suggested the ISO consider requesting an effective date that coincides with the start of a commitment period (e.g., June 1, 2021).

LITIGATION REPORT

Mr. Doot referred the Committee to the September 29 Litigation Report that had been circulated and posted in advance of the meeting. He then highlighted the following items:

(1) ***FCM Pricing Rules (7-year Price Lock) Complaint Remand Proceeding*** – Briefing had been completed in late September and the matter was back before the FERC.

(2) ***Mystic 8/9 Cost of Service (COS) Agreement*** **–** The orders in the Mystic 8/9 COS Agreement proceeding had been appealed to the DC Circuit, with appearances and initial submissions in the consolidated case due in October. Separately, initial briefs in the Return on Equity (ROE) paper hearing had been filed, with responses due in late October.

(3) ***CIP IROL Cost Recovery Rules*** **–** the FERC had issued an order further clarifying and addressing arguments raised by the IROL-Critical Facility Owners in their request for rehearing (which had earlier been denied by operation of law).

(4) ***Order 2222*** (Distributed Energy Resource (DER) Participation in ISO/RTO Markets) - the FERC had issued a final rule adopting reforms to the rules for the participation of DER aggregations in the RTO/ISO markets. Order 2222 required each RTO/ISO to revise its

tariff to ensure that its market rules facilitate the participation of DER aggregations. ISO-NE was still in the process of evaluating what might be required in response to that Order.

(5) ***NEPGA Exelon Complaint* –** pleadings addressing challenges to the rate in the Mystic COS Agreement (given new information about Exelon's two new queue positions and Exelon's intention to continue to operate the Everett LNG Terminal beyond the term of the Mystic COS Agreement) were submitted and before the FERC.

(6) ***Further Order 841 Compliance Filings* –** The FERC had granted revisions to the compliance deadlines it had established in its August 4 order that NEPOOL and ISO had jointly requested. As a result, the Participants Committee would receive and be asked to consider a full set of compliance changes at its December meeting, for filing shortly thereafter.

COMMITTEE REPORTS

Markets Committee (MC). Mr. Bill Fowler, MC Vice-Chair, reported that the MC was next scheduled to meet for three days, from October 6-8, with key items to include a vote to sunset the Forward Reserve Market on June 1, 2025 and on the Dynamic De-List Bid Thresholds to be in effect for FCA16-18. Voting on Net Cone items had been pushed back to the November Markets Committee meeting. He referred members to a process memo issued by the ISO a few days earlier for more information.

Transmission Committee (TC). Mr. José Rotger, TC Vice-Chair, reported that the TC was scheduled to meet on October 27, when it was expected to vote on the portion of the further Order 841 compliance filing changes that were properly subject to consideration by the TC.

B&F Subcommittee. Ms. Gardner noted that the next meeting of the Subcommittee was scheduled for October 5, at which the Subcommittee would discuss the ISO's proposed "Know Your Customer" (KYC) changes to the Financial Assurance Policy. All interested persons were urged to attend.

POTENTIAL FUTURE MARKET FRAMEWORKS IN LIGHT OF EXPECTED CHANGES TO NEW ENGLAND'S GRID

After a brief recess, the meeting resumed via WebEx. Ms. Chafetz introduced the discussion by identifying the three topics to be covered – (1) an overview of a new potential pathway – an "Integrated Clean Capacity Market" (ICCM); (2) preliminary observations and discussion on the tradeoffs of the first two potential pathways explored (a forward clean energy market (FCEM) and carbon pricing); and (3) a report from Mr. van Welie on the guidance provided by the ISO Board and expected process on those first two pathways.

Integrated Clean Capacity Market

Ms. Chafetz introduced Ms. Kathleen Spees, Principal of The Brattle Group, who provided an overview of an ICCM, which she described as a three-year forward market to attract the optimal resource mix for reliability and state policy goals. She explained that the ICCM would maintain key elements from the current FCM structure, but would be a fit-for-purpose market for achieving an 80-100% clean electricity future. Resources would clear the ICCM market based on combined bids for their capacity and the clean energy attributes based on the number of clean energy attribute certificates (CEAC) they could produce (with each certificate representing one MWh of clean energy). After explaining the framework, she compared the ICCM to other pathways/frameworks under consideration. She also reviewed the supply, demand and co-optimized auction clearing concepts of an ICCM.

In response to questions and discussion throughout her presentation, Ms. Spees clarified a number of aspects of the ICCM concept and identified areas that could be fine-tuned or would need to be finalized. She confirmed that state participation would be optional (though states could mandate constituent participation), and that state self-supply could be accommodated. She explained how ICCM would allow states to use competitive markets to achieve their goals, with the greatest benefits (lowest cost procurement) to states that opted for resource-neutral requirements. She clarified that Competitive Auctions with Sponsored Policy Resources (CASPR), which was designed to accommodate resources required by state laws, would not exist as part of the contemplated ICCM construct. The ICCM could be designed to reflect various carve outs that were not resource neutral in order to address certain state-specific requirements, but those carve-outs would reduce, and carve outs collectively could eventually eliminate, the benefits of competition. She recommended that resource requirements or preferences be expressed in units of measure (e.g., MW for capacity and MWh for CEACs) which, while not substitutable, would allow for solutions to be identified through advanced product definitions (e.g., CEACs for storage resources) and could be implemented in a way that allows for more flexible and desirable cooptimization.

Ms. Spees confirmed that, given the unbundled nature of the ICCM, existing or new resources could participate (and receive payments) just for their capacity, or as appropriate, participate just for CEAC, but would have to clear for both products if both were offered. Addressing allocation of procurement costs, she explained that costs for the capacity product would be allocated by peak load; clean energy costs would be allocated back to the customers seeking that product (either back to customers in a particular state that created the demand for that product as represented by the CEAC or to buyers that volunteered to procure that clean energy). She confirmed that it was possible for some portion of demand to be left unserved if the auction were to clear at a price higher than demand bid/was willing to pay.

ICCM aspects that could be fine-tuned or would require choices to be made included, for example, how CEACs would be valued (whether equally at all hours as are Renewable Energy Credits (RECs) or with dynamic or de-carbonization values layered in), the length of the forward period (three-year forward as modelled after the current FCM) or shorter or longer depending on the balance struck between maximizing resource participation and mitigating consumer risk borne with longer forward periods), how to ensure durability of demand (whether legislatively or some other way), the length of any price lock included in the design for new resources, and the role and parameters of any minimum offer price rule (MOPR).

Ms. Spees walked through an example of an ICCM auction clearing, including how demand curves would be used for each product, how resources would offer, how prices would be set, and what resources would clear, to illustrate how an ICCM could guide an energy transition. In response to questions, she suggested that market power, particularly on the capacity side of the market, would have to be closely monitored. She explained why unbundling clearing prices on the two sides of the market would result in higher prices but could be accommodated. She described the consequences to a Market Participant of producing both less and more of the product for which it received an obligation.

She concluded her presentation by reviewing advantages and challenges to consider if an ICCM is pursued. She confirmed the ability of existing and new resources to coexist in the ICCM construct, and expressed confidence that the attendant investment risk, whether or not mitigated through a price lock mechanism, could and would be assumed by the private sector.

Future Pathways - Round 1 Preliminary Observations: Focus on FCEM and Carbon Pricing

Ms. Chafetz then introduced Dr. Frank Felder, PhD, Director of the Center for Energy, Economic and Environmental Policy at Rutgers University and Director of the Rutgers Energy Institute who, as discussed earlier in the meeting, had been engaged to facilitate NEPOOL discussions of potential future pathways for New England. Dr. Felder stated that, by the end of December, he hoped to help build a common understanding among stakeholders of those pathways and their variations, and to produce a report that analyzes, with input from stakeholders, the tradeoffs associated with those pathways and variations. He said that his analysis would consider and compare whether and to what extent each of the pathways discussed (1) support the clean energy policies of the New England States and (2) garner efficiency of New England's markets.

Dr. Felder then proceeded to summarize and review slides, which had been circulated and posted in advance of the meeting, that reflected his preliminary observations on FCEM and carbon pricing concepts, including variations associated with each of those identified pathways. He noted that many of his points on the FCEM pathway had been addressed in the questions and discussion of the ICCM construct.

During his summary, members responded with initial questions, observations and requests. Members asked Dr. Felder to consider in his analysis how his conclusions might vary if carbon pricing was limited to the electric sector versus implemented economy-wide. He was also asked to consider in his analysis whether the impacts of carbon pricing on energy market pricing might suggest the need for other changes to the energy market design. Dr. Felder was asked further to identify how he saw the net carbon pricing option described by the ISO fitting in or aligning with the categories of carbon pricing concepts reflected in his presentation materials.

Dr. Felder expressed appreciation for the questions and suggestions and committed to consider them in his analysis. He concluded his presentation by encouraging Participants to provide written feedback and comments on this (or future) presentations. He asked that any such feedback be sent to Mr. Sebastian Lombardi, NEPOOL Counsel (slombardi@daypitney.com). It was noted that all comments received would be posted on the NEPOOL website (http://nepool.com/Fut_Grid_Poten_Pathways.php).

ISO's Planned Evaluation of FCEM and Net Carbon Pricing Concepts

Mr. van Welie referred back to the direction from the ISO Board that he had summarized earlier in the meeting -- that the ISO further study two of the potential pathways that had emerged in the Future Grid pathways process (FCEM and net carbon pricing). He proceeded to provide additional context, address the proposed process for undertaking that further assessment of the FCEM and net carbon pricing frameworks and answer Participant questions concerning his thoughts on the study or studies to be undertaken and the process to be utilized in connection that work on the pathways.

He identified three requirements in order to facilitate a clean energy transition in New England: (1) transmission; (2) financial support for and ensuring there would be sufficient clean energy resources; and (3) financial support for and ensuring the availability of sufficient balancing resources required to ensure reliability. Focusing on the latter two, he opined that both FCEM and net carbon pricing concepts would ensure the sufficiency of and payments for clean energy resources; while only net carbon pricing (and not FCEM) was likely to help, at least in part, with the sufficiency of and payments for balancing resources. He explained in response to questions that balancing resources, a term intended to be neutral, and viewed with a multi-day, rather than an operating day perspective, were those often low-capacity resources that would produce substitute or "fill in" energy for lost renewable resource output (e.g. when the wind is not blowing or the sun is not shining). He indicated that such resources would need to recover their costs in the market (increasingly in the capacity and not the energy market).

Addressing process, he expected that the ISO would pick up from and build off the efforts of Dr. Felder. The ISO ~~plans~~planned to work with stakeholders to establish the scope and assumptions to be used in its studies, producing and working through iterations of the results. He expected that the ISO would eventually be in a position to produce a qualitative assessment of FCEM and, for net carbon pricing, whose eventual market design was more clear to the ISO, to build a model to show the expected net impact on wholesale consumers. He clarified in response to questions that the ISO would evaluate any ~~broadly supported~~broadly-supported pathway that would be able to facilitate a clean energy transition (particularly those that would eliminate the MOPR and provide revenues for balancing resources). He emphasized that the ISO was not committing at this time to filing a market design based on either pathway, but rather would define in more detail what was going to be studied, distill the pathways for study, narrow variants, and then do a deeper dive. Some members encouraged the ISO to undertake its efforts sooner rather than later. Mr. van Welie expected the studies to take six to nine months, depending on the scope established in the stakeholder process, with results available no earlier than mid-2021.

In response to questions, Mr. van Welie indicated that the ISO had considered in its initial discussions the development of some form of residual capacity market, but had ultimately concluded that such a market was not likely to be efficient or effective. In response to questions on carbon pricing specifically, he noted two challenges that would need to be addressed – the fear that carbon pricing might result in significant increases in the wholesale price of electricity and jurisdictional challenges. He was hopeful that the studies would show that net carbon pricing would result in moderate, rather than significant, price increases and, when coupled with an ISO-implemented vehicle through which the states would set prices (presuming RGGI itself is unable alone to produce an adequate price to achieve desired outcomes), would produce tangible and desirable regional benefits, thereby allowing the states to support rather than oppose net carbon pricing. He acknowledged that the net carbon pricing construct could be implemented with some sub-set of the New England states participating, but that variant would require careful consideration and agreement with those states on revenue disbursement issues.

Next Steps

Ms. Chafetz indicated that anyone wishing to explore additional potential pathways should let her or NEPOOL Counsel know as soon as possible but no later than Friday, October

16. Time would be set aside at the November 5 Participants Committee meeting should any other potential pathways/market constructs be so identified. Dr. Felder will be at the November 5 meeting to present his preliminary observations on the remaining pathways presented in September and October. Dr. Felder would then update his observations and analysis based on further information and stakeholder feedback, and finalize a written report reflecting his efforts.

There being no further business, the meeting adjourned at 4:53 p.m.

Respectfully submitted,

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David Doot, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN OCTOBER 1, 2020 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Acadia Center	End User	***Deborah Donovan***		***Phelps Turner***
Advanced Energy Economy	Fuels Industry Participant	***Caitlin Marquis***		
American PowerNet Management	Supplier			Mary Smith
AR Small Load Response (LR) Group Member	AR-LR	***Doug Hurley***	***Brad Swalwell***	
AR Small Renewable Generation (RG) Group Member	AR-RG	***Erik Abend***		
Ashburnham Municipal Light Plant	Publicly Owned Entity		***Brian Thomson***	
Associated Industries of Massachusetts (AIM)	End User			***Roger Borghesani***
AVANGRID: CMP/UI	Transmission		***Alan Trotta***	
Belmont Municipal Light Department	Publicly Owned Entity		***Dave Cavanaugh***	
Block Island Utility District	Publicly Owned Entity	***Dave Cavanaugh***		
Borrego Solar Systems Inc.	AR-DG	***Liz Delaney***		Michael Macrae
Boylston Municipal Light Department	Publicly Owned Entity		***Brian Thomson***	
BP Energy Company	Supplier			***José Rotger***
Braintree Electric Light Department	Publicly Owned Entity			***Dave Cavanaugh***
Brookfield Renewable Trading and Marketing	Supplier	***Aleks Mitreski***		
Calpine Energy Services, LP	Supplier	***Brett Kruse***		***Bill Fowler***
Castleton Commodities Merchant Trading	Supplier			***Bob Stein***
Central Rivers Power	AR-RG		***Dan Allegretti***	
Chester Municipal Light Department	Publicly Owned Entity		***Dave Cavanaugh***	
Chicopee Municipal Lighting Plant	Publicly Owned Entity		***Brian Thomson***	
CLEAResult Consulting, Inc.	AR-DG	***Tamera Oldfield***		
Concord Municipal Light Plant	Publicly Owned Entity		***Dave Cavanaugh***	
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	***Brian Forshaw***		
Connecticut Office of Consumer Counsel	End User		***Dave Thompson***	
Conservation Law Foundation (CLF)	End User	***Phelps Turner***		
Cross-Sound Cable Company (CSC)	Supplier		***José Rotger***	
Danvers Electric Division	Publicly Owned Entity		***Dave Cavanaugh***	
Direct Energy Business, LLC	Supplier	***Nancy Chafetz***		
Dominion Energy Generation Marketing, Inc.	Generation	Mike Purdie	Weezie Nuara	
DTE Energy Trading, Inc.	Supplier			***José Rotger***
Dynegy Marketing and Trade, LLC	Supplier	***Andy Weinstein***		
Emera Energy Services	Supplier			***Bill Fowler***
Enel X North America, Inc.	AR-LR	***Michael Macrae***		
ENGIE Energy Marketing NA, Inc.	AR-RG	***Sarah Bresolin***		
Environmental Defense Fund	End User	***Jolette Westbrook***		
Eversource Energy	Transmission	***James Daly***	***Dave Burnham***	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	Dennis Duffy	***Abby Krich***	Alex. Worsley
Georgetown Municipal Light Department	Publicly Owned Entity		***Dave Cavanaugh***	
Great River Hydro	AR-RG			***Bill Fowler***
Groton Electric Light Department	Publicly Owned Entity		***Brian Thomson***	
Groveland Electric Light Department	Publicly Owned Entity		***Dave Cavanaugh***	
H.Q. Energy Services (U.S.) Inc. (HQUS)	Supplier	***Louis Guibault***	***Bob Stein***	
Harvard Dedicated Energy Limited	End User	***Mary Smith***	***Joyceline Chow***	***Roger Borghesani***
High Liner Foods (USA) Incorporated	End User		***William P. Short III***	
Hingham Municipal Lighting Plant	Publicly Owned Entity		***Dave Cavanaugh***	

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN OCTOBER 1, 2020 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
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***	
Industrial Energy Consumer Group	End User	***Kevin Penders***		
Ipswich Municipal Light Department	Publicly Owned Entity		***Brian Thomson***	
Jericho Power LLC (Jericho)	AR-RG	***Mark Spencer***		
Littleton (MA) Electric Light and Water Department	Publicly Owned Entity		***Dave Cavanaugh***	
Littleton (NH) Water & Light Department	Publicly Owned Entity		Craig Kieny	
Long Island Power Authority (LIPA)	Supplier		***Bill Killgoar***	
Maine Power	Supplier	***Jeff Jones***		
Maine Public Advocate’s Office	End User	Drew Landry		***Erin Camp***
Maine Skiing, Inc.	End User	***Kevin Penders***		
Mansfield Municipal Electric Department	Publicly Owned Entity		***Brian Thomson***	
Maple Energy LLC	AR-LR		***Luke Fishback***	***Doug Hurley***
Marble River, LLC	Supplier		John Brodbeck	
Marblehead Municipal Light Department	Publicly Owned Entity		***Brian Thomson***	
Mass. Attorney General’s Office (MA AG)	End User	***Tina Belew***	***Ben Griffiths***	
Mass. Bay Transportation Authority	Publicly Owned Entity		***Dave Cavanaugh***	
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity	***Brian Thomson***		
Mercuria Energy America, LLC	Supplier			***José Rotger***
Merrimac Municipal Light Department	Publicly Owned Entity		***Dave Cavanaugh***	
Michael Kuser	End User		Jason York	Rich Heidorn
Middleborough Gas & Electric Department	Publicly Owned Entity		***Dave Cavanaugh***	
Middleton Municipal Electric Department	Publicly Owned Entity		***Dave Cavanaugh***	
National Grid	Transmission	***Tim Brennan***	Tim Martin	
Natural Resources Defense Council (NRDC)	End User	***Bruce Ho***		
Nautilus Power, LLC	Generation		***William Fowler***	
New Hampshire Electric Cooperative	Publicly Owned Entity	Steve Kaminski		***Brian. Forshaw; Dave Cavanaugh; Brian Thomson***
New Hampshire Office of Consumer Advocate (NHOCA)	End User		***Erin Camp***	
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	
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***	
PowerOptions, Inc.	End User			***Erin Camp***
Princeton Municipal Light Department	Publicly Owned Entity		***Brian Thomson***	
Priogen Power LLC	Supplier	Michel Soucy		
PSEG Energy Resources & Trade LLC	Supplier	***Joel Gordon***		***Mark Spencer***
Reading Municipal Light Department	Publicly Owned Entity		***Dave Cavanaugh***	
Rowley Municipal Lighting Plant	Publicly Owned Entity		***Dave Cavanaugh***	
Russell Municipal Light Dept.	Publicly Owned Entity		***Brian Thomson***	
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		***Brian Thomson***	
South Hadley Electric Light Department	Publicly Owned Entity		***Brian Thomson***	
Sterling Municipal Electric Light Department	Publicly Owned Entity		***Brian Thomson***	
Stowe Electric Department	Publicly Owned Entity		***Dave Cavanaugh***	
Sunrun Inc.	AR-DG			Pete Fuller

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN OCTOBER 1, 2020 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Taunton Municipal Lighting Plant	Publicly Owned Entity		***Dave Cavanaugh***	
Templeton Municipal Lighting Plant	Publicly Owned Entity		***Brian Thomson***	
The Energy Consortium	End User	***Roger Borghesani***	Mary Smith	
Vermont Electric Cooperative	Publicly Owned Entity	Craig Kieny		
Vermont Electric Power Co. (VELCO)	Transmission	***Frank Ettori***		
Vermont Energy Investment Corp (VEIC)	AR-LR		***Doug Hurley***	
Vermont Public Power Supply Authority	Publicly Owned Entity			***Brian Forshaw***
Versant Power	Transmission	***Lisa Martin***		
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity		***Dave Cavanaugh***	
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***	

VOTE TAKEN AT
OCTOBER 1, 2020 PARTICIPANTS COMMITTEE MEETING

TOTAL

Sector	Vote 1	Vote 2
GENERATION	16.70	16.70
TRANSMISSION	16.70	16.70
SUPPLIER	16.70	16.70
ALTERNATIVE RESOURCES	8.25	11.00
PUBLICLY OWNED ENTITY	0.00	16.70
END USER	0.00	1.67
% IN FAVOR	**58.35**	**79.47**

GENERATION SECTOR

Participant Name	Vote 1	Vote 2
Dominion Energy Generation Mktg.	F	F
FirstLight Power Resources Mgmt.	F	F
Generation Group Member	A	F
Nautilus Power, LLC	F	F
NextEra Energy Resources, LLC	F	F
NRG Power Marketing, LLC	F	F
IN FAVOR (F)	5	6
OPPOSED (O)	0	0
TOTAL VOTES	5	6
ABSTENTIONS (A)	1	0

TRANSMISSION SECTOR

Participant Name	Vote 1	Vote 2
Avangrid (CMP/UI)	A	A
Eversource Energy	F	F
National Grid	F	F
Versant Power	F	A
IN FAVOR (F)	3	2
OPPOSED	0	0
TOTAL VOTES	3	2
ABSTENTIONS (A)	1	2

SUPPLIER SECTOR

Participant Name	Vote 1	Vote 2
BP Energy Company	F	F
Brookfield Renewable Trading & Mktg	F	F
Calpine Energy Services, LP	F	F
Castleton Comm. Merchant Trading	F	F
Cross-Sound Cable Company	A	A
Direct Energy Business, LLC	F	F
DTE Energy Trading, Inc.	F	F
Dynegy Marketing and Trade, LLC	F	F
Emera Energy Companies	A	A
Exelon Generation Company	A	F
Galt Power, Inc.	F	F
H.Q. Energy Services (U.S.) Inc.	F	F
LIPA	A	A
Marble River, LLC	A	A
Mercuria Energy America, Inc	F	F
Priogen Power LLC	A	A
PSEG Energy Resources & Trade	F	F
IN FAVOR (F)	11	12
OPPOSED	0	0
TOTAL VOTES	11	12
ABSTENTIONS (A)	6	5

ALTERNATIVE RESOURCES SECTOR

Participant Name	Vote 1	Vote 2
Renewable Generation Sub-Sector		
Central Rivers Power	F	F
ENGIE Energy Marketing NA	A	F
Great River Hydro	F	F
Jericho Power	F	F
Wheelabrator/Macquarie	F	F
Small RG Group Member	A	A
Distributed Gen. Sub-Sector		
Borrego Solar Systems Inc.	A	--
CLEAResult Consulting, Inc.	A	A
Sunrun Inc.	O	O
Load Response Sub-Sector		
Enel X North America, Inc.	A	A
Maple Energy	O	O
Vermont Energy Investment Corp.	O	O
Small LR Group Member	O	O
IN FAVOR (F)	4	5
OPPOSED	4	3
TOTAL VOTES	8	8
ABSTENTIONS (A)	5	4

VOTE TAKEN AT
OCTOBER 1, 2020 PARTICIPANTS COMMITTEE MEETING

END USER SECTOR

Participant Name	Vote 1	Vote 2
Acadia Center	O	O
Associated Industries of Mass.	O	A
Conn. Office of Consumer Counsel	O	O
Conservation Law Foundation	O	O
Environmental Defense Fund	O	--
Harvard Dedicated Energy Limited	O	A
High Liner Foods (USA) Inc.	O	F
Industrial Energy Consumer Group	O	A
Michael Kuser	A	A
Maine Public Advocate Office	O	O
Maine Skiing, Inc.	O	A
Mass. Attorney General's Office	O	O
Natural Resources Defense Council	O	O
NH Office of Consumer Advocate	O	O
PowerOptions, Inc.	O	O
The Energy Consortium	O	O
IN FAVOR (F)	0	1
OPPOSED	15	9
TOTAL VOTES	15	10
ABSTENTIONS (A)	1	5

PUBLICLY OWNED ENTITY SECTOR

Participant Name	Vote 1	Vote 2
Ashburnham Municipal Light Plant	A	F
Belmont Municipal Light Dept.	A	F
Block Island Utility District	A	F
Boylston Municipal Light Dept.	A	F
Braintree Electric Light Dept.	A	F
Chester Municipal Light Dept.	A	F
Chicopee Municipal Lighting Plant	A	F
Concord Municipal Light Plant	A	F
Conn. Mun. Electric Energy Coop.	A	F
Danvers Electric Division	A	F
Georgetown Municipal Light Dept.	A	F
Groton Electric Light Dept.	A	F
Groveland Electric Light Dept.	A	F
Hingham Municipal Lighting Plant	A	F
Holden Municipal Light Dept.	A	F
Holyoke Gas & Electric Dept.	A	F
Hull Municipal Lighting Plant	A	F

PUBLICLY OWNED ENTITY SECTOR (cont.)

Participant Name	Vote 1	Vote 2
Ipswich Municipal Light Dept.	A	F
Littleton (MA) Electric Light Dept.	A	F
Mansfield Municipal Electric Dept.	A	F
Marblehead Municipal Light Dept.	A	F
Mass. Bay Transportation Authority	A	F
Mass. Mun. Wholesale Electric Co.	A	F
Merrimac Municipal Light Dept.	A	F
Middleborough Gas and Elec. Dept.	A	F
Middleton Municipal Electric Dept.	A	F
New Hampshire Electric Cooperative	A	F
North Attleborough Electric Dept.	A	F
Norwood Municipal Light Dept.	A	F
Pascoag Utility District	A	F
Paxton Municipal Light Dept.	A	F
Peabody Municipal Light Plant	A	F
Princeton Municipal Light Dept.	A	F
Reading Municipal Light Dept.	A	F
Rowley Municipal Lighting Plant	A	F
Russell Municipal Light Dept.	A	F
Shrewsbury's Elec. & Cable Ops.	A	F
South Hadley Electric Light Dept.	A	F
Sterling Municipal Electric Light Dept.	A	F
Stowe (VT) Electric Dept.	A	F
Taunton Municipal Lighting Plant	A	F
Templeton Municipal Lighting Plant	A	F
Village of Hyde Park (VT) Elec. Dept.	A	F
VT Public Power Supply Authority	A	F
Wakefield Mun. Gas and Light Dept.	A	F
Wallingford, Town of	A	F
Wellesley Municipal Light Plant	A	F
West Boylston Mun. Lighting Plant	A	F
Westfield Gas & Electric Light Dept.	A	F
IN FAVOR (F)	0	49
OPPOSED	0	0
TOTAL VOTES	0	49
ABSTENTIONS (A)	49	0

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CONSENT AGENDA

Markets Committee

From the previously-circulated notice of actions of the Markets Committee's October 6-8, 2020 meeting, dated October 14, 2020:[1]

1. **PRIOR TO ACTION ON THE CONSENT AGENDA, THIS ITEM WAS REMOVED WITHOUT OBJECTION**
Revisions to Market Rule 1 § 9.1 (Forward Reserve Market Sunset)

Support revisions to section III.9.1 of Market Rule 1 reflecting the sunset of the Forward Reserve Market (including the language contingent on the FERC's acceptance of key components of the ISO's Energy Security Improvements proposal), as recommended by the Markets Committee at its October 6-8, 2020 meeting, with such further non-material changes as the Chair and Vice-Chair of the Markets Committee may approve.

The motion to recommend Participants Committee support was approved, with one opposition in the Supplier Sector and abstentions in each Sector -- Generation (1), Transmission (1), Supplier (5), Publicly Owned Entity (21), AR (40), and End User (1) -- noted.

Reliability Committee

From the previously-circulated notice of actions of the Reliability Committee's October 20, 2020 meeting, dated October 20, 2020:[2]

2. **Revisions to the ISO-NE/NYISO Coordination Agreement (Revisions to Schedule A (Description of Interconnection Facilities) and a jointly developed ISO-NE/NYISO List of Interconnection Facilities to be posted on the ISO-NE and NYISO external websites)**

Support revisions to the ISO-NE and NYISO Coordination Agreement and a supporting ISO-NE/NYISO List of Interconnection Facilities that will be posted on the ISO-NE and NYISO websites (intended to add efficiencies and reduce filing requirements related to modifications to the existing Interconnections between ISO-NE and the NYISO), as recommended by the Reliability Committee at its October 20, 2020 meeting, with such further non-material changes as the Chair and Vice-Chair of the Reliability Committee may approve.

The motion to recommend Participants Committee support was approved unanimously.

[continued on next page]

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

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

3. <u>HQICC Values for the 2021-22 3rd ARA, 2022-23 2nd ARA, and 2023-24 1st ARA</u>

Support the following Hydro-Québec Interconnection Capability Credit (HQICC) values for the Third Annual Reconfiguration Auction (ARA) for the 2021-22 Capacity Commitment Period (CCP), Second ARA for the 2022-23 CCP and First ARA for the 2023-24 CCP, as recommended by the Reliability Committee at its October 20, 2020 meeting, with such further non-material changes as the Chair and Vice-Chair of the Reliability Committee may approve:

Month	2021-2022 HQICC Values (MW)	2022-2023 HQICC Values (MW)	2023-2024 HQICC Values (MW)
June	854	969	941
July	854	969	941
August	854	969	941
September	854	969	941
October	854	969	941
November	854	969	941
December	854	969	941
January	854	969	941
February	854	969	941
March	854	969	941
April	854	969	941
May	854	969	941

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

[continued on next page]

4. ICR and Related Values for the 2021-22 3rd ARA, 2021-23 2nd ARA and 2022-24 1st ARA

3rd ARA for the 2021-22 CCP

Support, for the 3rd ARA for the 2021-22 CCP, the following New England ICR, Net ICR, Southeast New England (SENE) LSR, and Northern New England (NNE) Maximum Capacity Limit (MCL) values:

	2021-2022 ARA 3 ICR values (MW)
Installed Capacity Requirement	33,779
Net Installed Capacity Requirement	32,925
Southeast New England Local Sourcing Requirement	9,511
Northern New England Maximum Capacity Limit	8,695

and the following Marginal Reliability Impact (MRI) Capacity Demand Curves -- System-Wide, SENE Import-Constrained Capacity Zone, and the NNE Export-Constrained Capacity Zone:

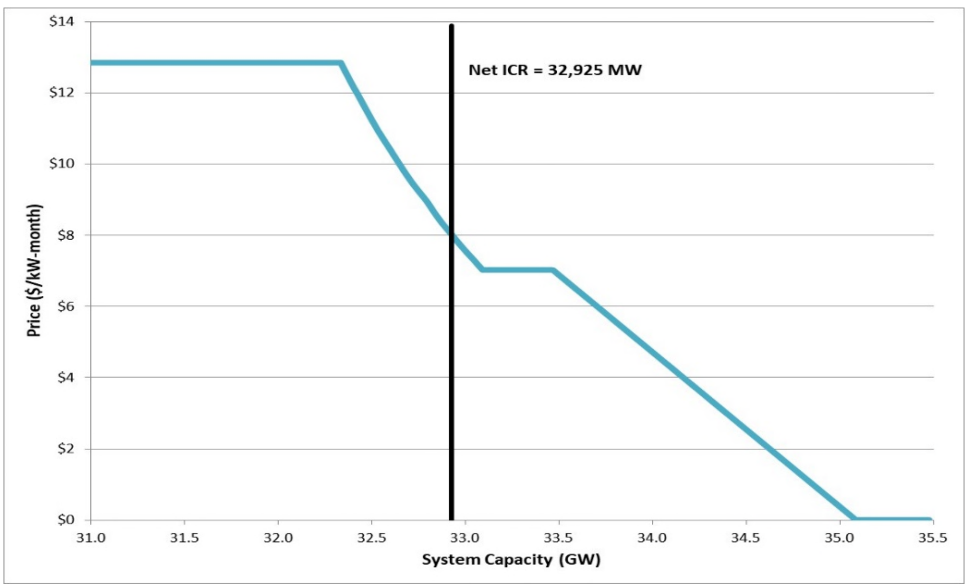


Figure 1 2021-22 CCP ARA3 System-Wide MRI Capacity Demand Curve

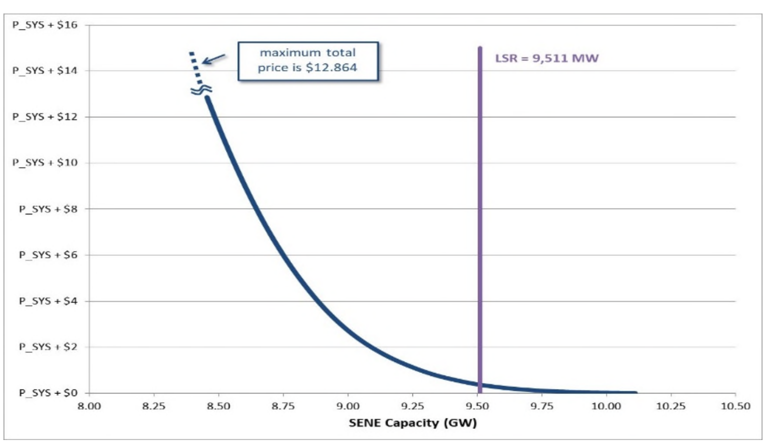


Figure 2 2021-22 CCP ARA3 SENE MRI Capacity Demand Curve

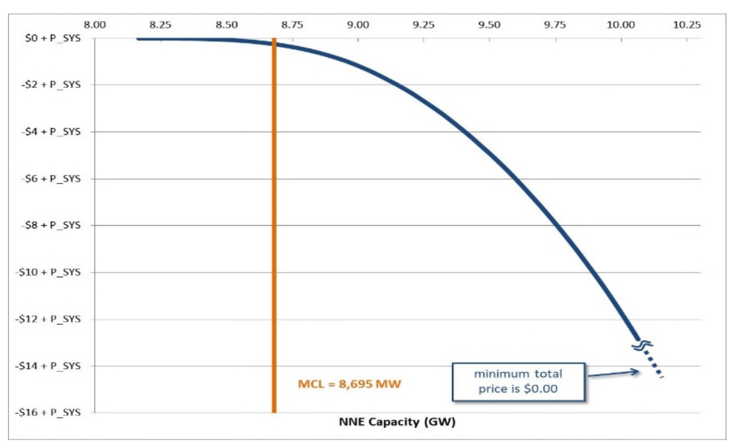


Figure 3 2021-22 CCP ARA3 NNE MRI Capacity Demand Curve

2nd ARA for the 2022-23 CCP

Support, for the 2nd ARA for the 2022-23 CCP, the following New England ICR, Net ICR, SENE LSR, and NNE MCL values:

	2022-2023 ARA 2 ICR values (MW)
Installed Capacity Requirement	33,734
Net Installed Capacity Requirement	32,765
Southeast New England Local Sourcing Requirement	9,633
Northern New England Maximum Capacity Limit	8,740

and the following MRI Capacity Demand Curves -- System-Wide, SENE Import-Constrained Capacity Zone, and the NNE Export-Constrained Capacity Zone:

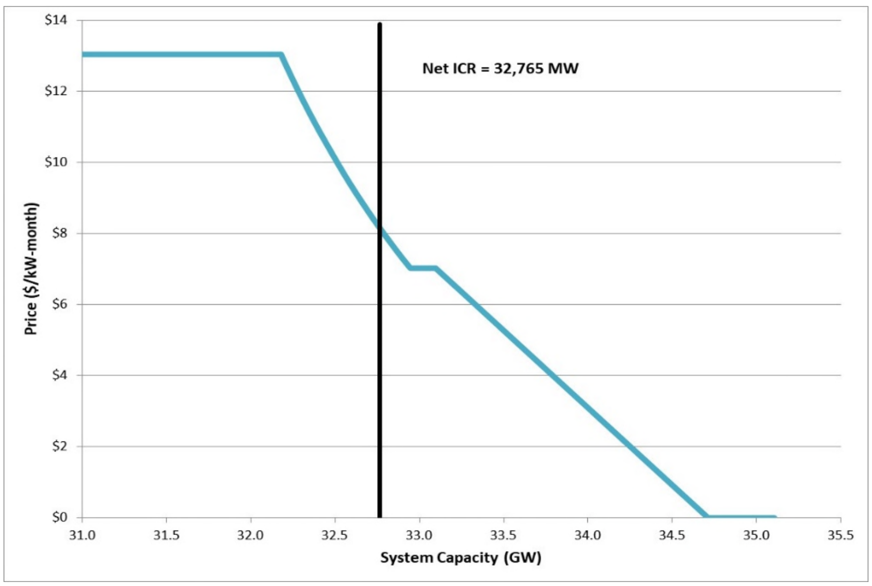


Figure 4 2022-23 CCP ARA2 System-Wide MRI Capacity Demand Curve

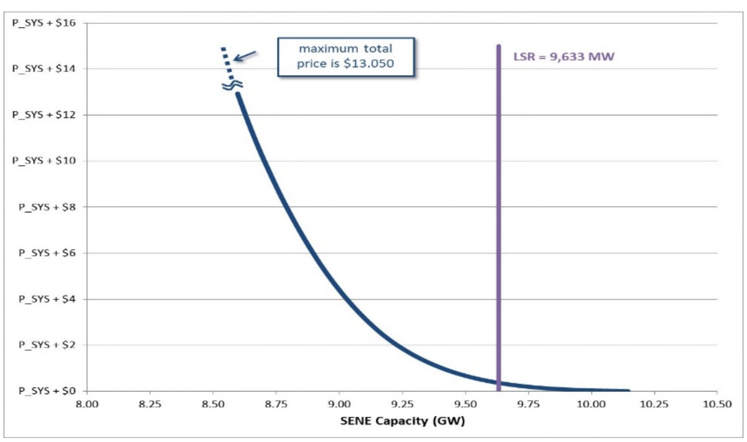


Figure 5 2022-23 CCP ARA3 SENE MRI Capacity Demand Curve

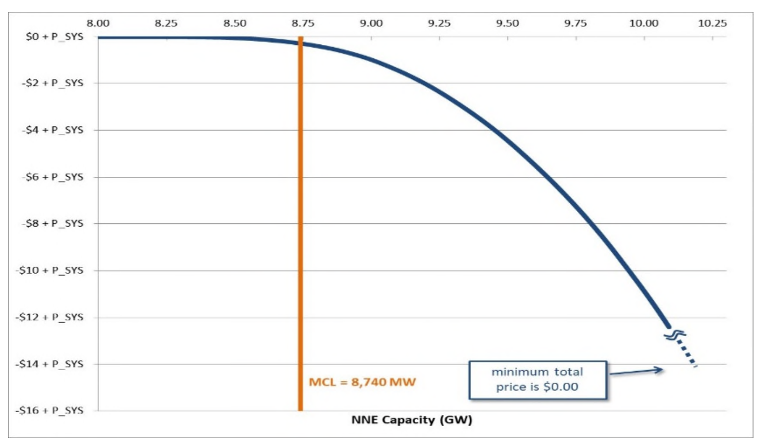


Figure 6 2022-23 CCP ARA3 NNE MRI Capacity Demand Curve

1st ARA for the 2023-24 CCP

Support, for the 1st ARA for the 2023-24 CCP, the following New England ICR, Net ICR, SENE LSR, Maine MCL, and NNE MCL values:

	2023-2024 ARA 1 ICR values (MW)
Installed Capacity Requirement	33,921
Net Installed Capacity Requirement	32,980
Southeast New England Local Sourcing Requirement	9,798
Maine Maximum Capacity Limit	4,295
Northern New England Maximum Capacity Limit	8,800

and the following MRI Capacity Demand Curves -- System-Wide, SENE Import-Constrained Capacity Zone, Maine Export-Constrained Capacity Zone, and the NNE Export-Constrained Capacity Zone:

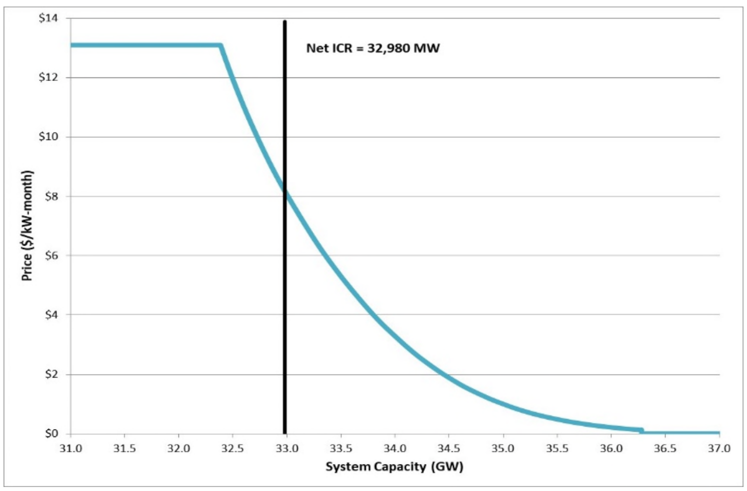


Figure 7 2023-24 CCP ARA1 System-Wide MRI Capacity Demand Curve

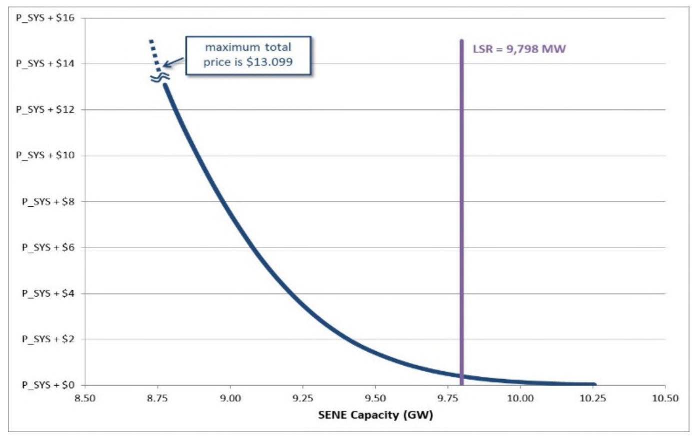


Figure 8 2023-24 CCP ARA1 SENE MRI Capacity Demand Curve

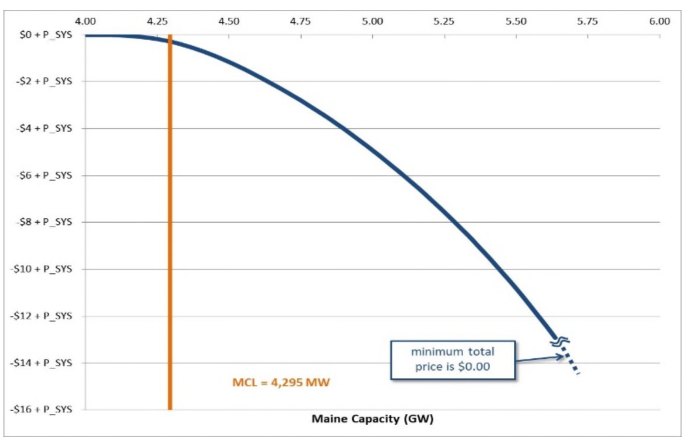


Figure 9 2023-24 CCP ARA1 Maine MRI Capacity Demand Curve

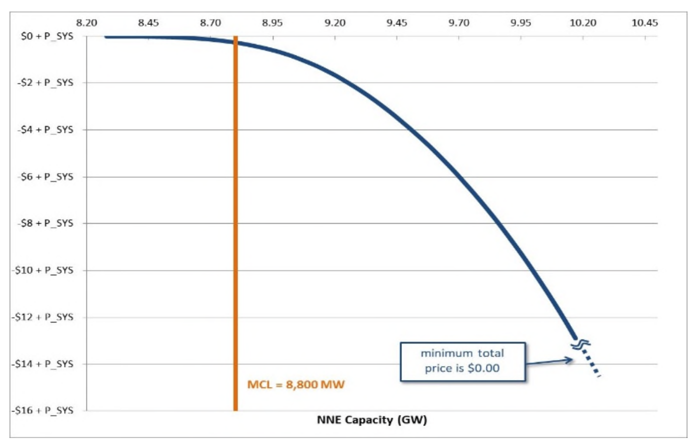


Figure 10 2023-24 CCP ARA1 NNE MRI Capacity Demand Curve

each as recommended by the Reliability Committee at its October 20, 2020 meeting, with such further non-material changes as the Chair and Vice-Chair of the Reliability Committee may approve.

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

Summary of ISO New England Board and Committee Meetings

November 5, 2020 Participants Committee Meeting

Since the last update, the Nominating and Governance Committee met on October 7, and the Markets Committee met on October 22. The Board of Directors met on October 16 and 22. All meetings were held virtually.

The Nominating and Governance Committee conducted its annual assessment of the risks within the Committee's purview, and developed recommended changes to committee assignments. The revised committee assignments will be considered by the Board at its November 4 meeting, and will be reported in the next CEO update to the Participants Committee. The Committee also discussed the orientation process for new Board member, Mark Vannoy.

The Markets Committee received an update on the FCM parameters project and discussed specific parameters, including Offer Review Trigger Prices. The Committee discussed management's proposals and stakeholder amendments. The System Planning and Reliability Committee joined the meeting for a discussion of the annual risk assessment related to markets and system planning. The risks focused on resource adequacy and operations issues associated with the transition to a renewable and DER-heavy grid. The Committees were then joined by the remaining board members to receive a presentation from Energy+Environmental Economics on the decarbonization of the New England economy and implications for the power system.

The Board of Directors met on October 16 to discuss the Board's annual self-evaluation process, and on October 22 to discuss the recent statement and vision documents issued by the New England states.

NOVEMBER 5, 2020

Overview of Strategic Planning

NEPOOL Participants Committee

The Annual Process – Strategic Planning

ISO-NE is guided by a purposeful and integrated business planning approach that drives focus towards a common target that management teams and the entire organization can get behind, with the aim of creating value for ISO stakeholders

ISO New England's Vision

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

Vision Statement:

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

Strategic Goals

Strategic Goals create context and guide the Annual Work Plan

Strategic Goals

- **Responsive Market Designs:** Improve the current market structure and continue to evolve and reposition the market design to accommodate the states' objectives and the transition to high levels of renewables and distributed resources. Maintain a robust fleet of balancing resources and preserve the ability of the market to attract new entry

- **Progress and Innovation:** Evolve capabilities to support the grid as the region transitions to clean energy, including improved power system and market modeling. Support investments in transmission infrastructure to enable renewable energy. Facilitate the integration of distributed energy resources. Provide data and information-based services

- **Operational Excellence**: Continuously improve operations and processes, with a focus on efficiency and effectiveness, business results, and continuity of operations

- **Stakeholder Engagement:** Collaboratively understand and anticipate needs, demonstrate thought leadership through high quality analysis and communication, and nurture productive relationships with FERC, the states and market participants

- **Attract, Develop, and Retain Talent:** Develop a sense of community around our Core Values, Mission, Vision and Goals, prepare the workforce, recognize and reward employee's success and innovation, and honor diversity and promote inclusion

DISCUSSION

NEPOOL Participants Committee Report

November 2020

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: September 2020 Energy Market value totaled $207M
  - October 2020 Energy market value was $193M over the period, down $14M from September 2020 and down $9M from October 2019
    - October natural gas prices over the period were 5.5% higher than September average values
    - Average RT Hub Locational Marginal Prices ($25.06/MWh) over the period were 26% higher than September averages
      - DA Hub: $22.39/MWh
    - Average October 2020 natural gas prices and RT Hub LMPs over the period were down 8% and up 23%, respectively, from October 2019 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 100.7% during October, up from 99.3% during September*
    - The minimum value for the month was 95.6% on Thursday, October 8th

Data through October 28th, except where otherwise noted.

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

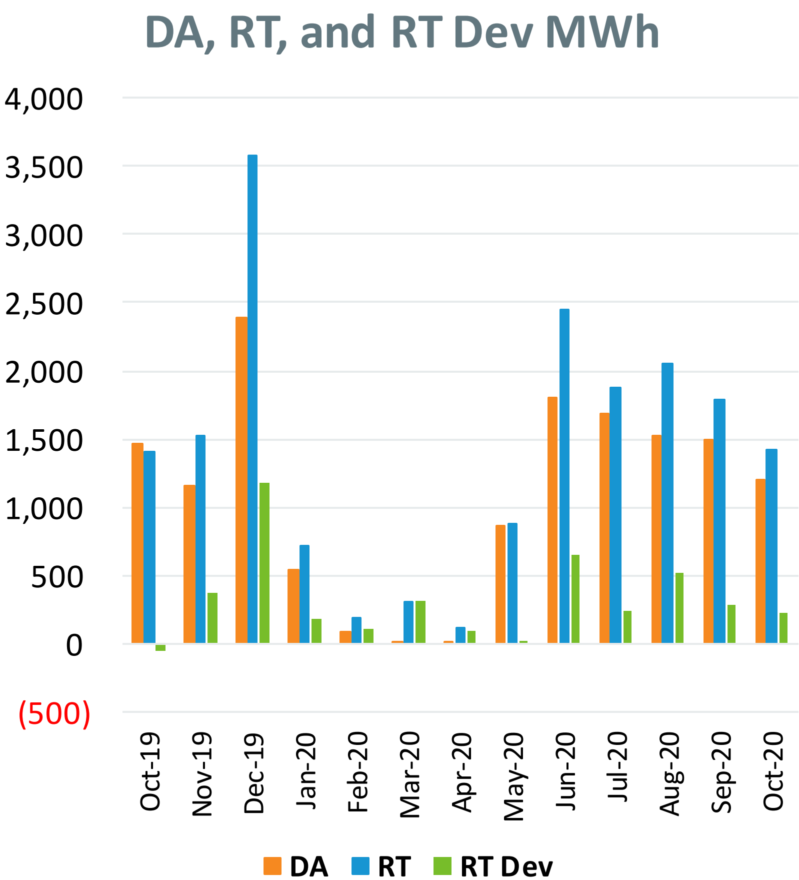
*DA Cleared Physical Energy is the sum of Generation and Net Imports cleared in the DA Energy Market

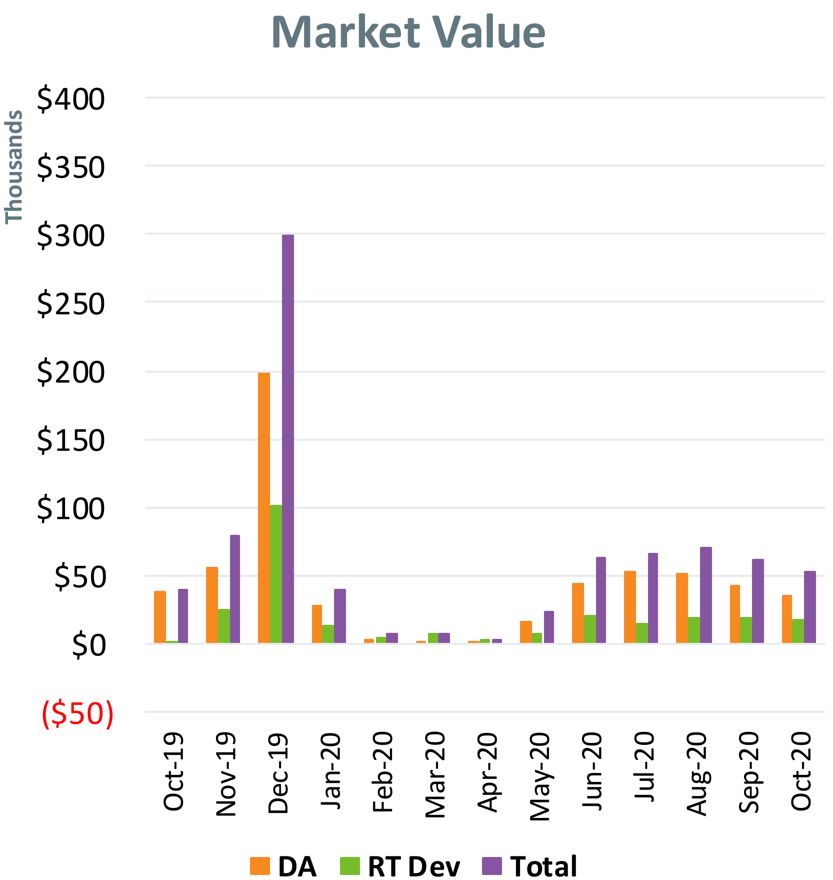
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - October 2020 NCPC payments totaled $2.5M over the period, up $0.1M from September 2020 and down $0.2M from October 2019
    - First Contingency payments totaled $1.9M, up $0.3M from September
      - $1.7M paid to internal resources, up $0.2M from September
        - » $514K charged to DALO, $620K to RT Deviations, $590K to RTLO*
      - $191K paid to resources at external locations, up $106K from September
        - » Charged to RT Deviations
    - Second Contingency payments totaled $546K, up $226K from September
    - Voltage payments totaled $43K, down $457K from September
    - Distribution payments totaled $41K, up $35K from September
  - NCPC payments over the period as percent of Energy Market value were 1.3%

*** NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $214K; Rapid Response Pricing (RRP) Opportunity Cost - $306K; Posturing - $12K; Generator Performance Auditing (GPA) - $57K**

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.

Forward Capacity Market (FCM) Highlights

- CCP 11 (2020-2021)
  - Third and final annual reconfiguration auction (ARA3) was held March 2-4 and results were posted on April 1
- CCP 12 (2021-2022)
  - ARA2 was held August 3-5 and results were posted on September 1
  - ICR and related values to be filed with FERC by December 1
    - RC supported the values with a positive vote on October 20

CCP – Capacity Commitment Period
ICR – Installed Capacity Requirement

Forward Capacity Market (FCM) Highlights

- CCP 13 (2022-2023)
  - ARA1 was held June 1-3, and results were posted on June 25
  - ICR and related values to be filed with FERC by December 1
    - RC supported the values with a positive vote on October 20
- CCP 14 (2023-2024)
  - Auction results were filed with FERC on February 18 and FERC accepted the filing on April 10
  - ICR and related values to be filed with FERC by December 1
    - RC supported the values with a positive vote on October 20

FCM Highlights, cont.

- CCP 15 (2024-2025)
  - It was confirmed at the May 28 PSPC meeting that FCA 15 will model the same zones as FCA 14
    - Export-constrained zones: Maine nested inside Northern New England
    - Import-constrained zone: Southeast New England
  - Existing capacity values were posted on March 6
  - Summary of retirement and permanent delist bids was posted on March 18 and summary of substitution auction demand bids was posted on May 1
  - Qualification Determination Notifications were released on October 2
  - Both the ICR and Informational (qualification) FERC filings will be made on November 10

FCA – Forward Capacity Auction

FCM Highlights, cont.

- CCP 16 (2025-2026)
  - The qualification process has started, and training materials are under development
  - Topology certifications were sent to the TOs on October 1
    - 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 2021 meeting
  - Capacity zone development discussions will begin at the November 19 PAC meeting
    - All subsequent reconfiguration auctions model the same zones as the FCA

Highlights

- At the October 21 Planning Advisory Committee (PAC) meeting, the ISO began the Order 1000/Boston 2028 Request for Proposal lessons-learned process related to competitive transmission solutions
- Both the ICR and Informational (qualification) FERC filings will be made on November 10
  - 2021 Annual Reconfiguration Auction values to be filed with FERC by December 1
- Capacity zone development discussions will begin at the November 19 PAC meeting
- Additional discussion on Transmission Planning for the Clean-Energy Transition will take place at the November 19 PAC meeting

Load Forecast

- Efforts continue to enhance load forecast models and tools to improve day-ahead and long-term load forecast performance
  - Discussions are ongoing with industry experts regarding emerging technologies/trends and methods of incorporating these into the forecast
- The 2021 load forecast development process has commenced
  - Discussions will continue at the Load Forecast Committee, Energy-Efficiency Forecast Working Group, and Distributed Generation Forecast Working Group through the rest of 2020 and into Q1 2021
  - In the March/April timeframe, PAC will discuss the preliminary ten-year forecast
  - Publication of the final ten-year forecast will be in the May 2021 CELT report

Competitive Solution Process: Order 1000/Boston 2028 Request for Proposal Lessons Learned

- The ISO began one-on-one discussions with each QTPS that participated in the Boston 2028 RFP where QTPS specific questions regarding their proposals and/or the process can be discussed
- The lessons-learned process, with respect to competitive transmission solutions, was discussed at the October PAC meeting
  - This effort will continue through the end of 2020 and into 2021

Highlights

- The lowest 50/50 and 90/10 Fall Operable Capacity Margins are projected for week beginning November 14, 2020.

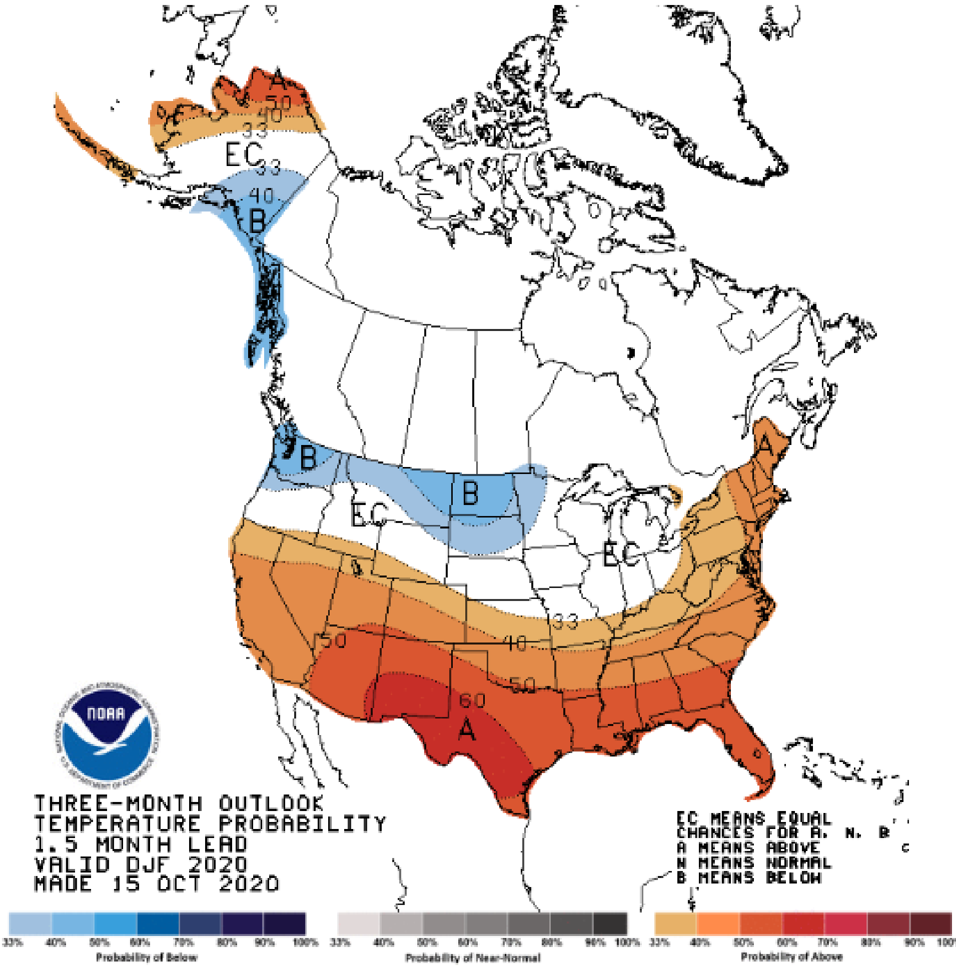
- The lowest 50/50 and 90/10 Winter Operable Capacity Margins are projected for week beginning January 2, 2021.

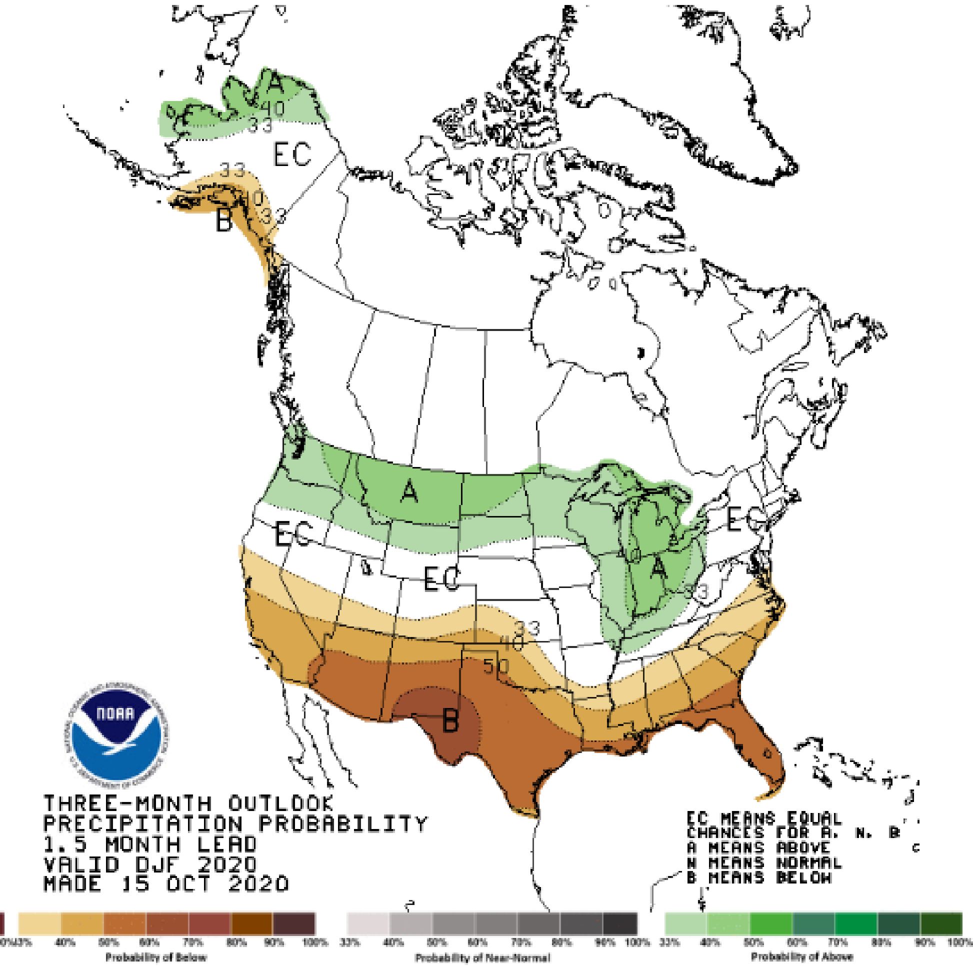
2020-2021 Winter Outlook

Highlights – Winter Outlook

- The seasonal temperature outlook for the winter months of December-January-February indicates a 40% probability of above-normal temperatures for all of New England
- An equal chance for above-average or below-average precipitation is forecasted across all of New England
- Winter Capacity Outlook
  - Projecting the lowest 50/50 operable capacity margin of 2,574 MW and 90/10 capacity margin of 1,232 MW for the week beginning January 2, 2021
  - In case of extended periods of cold weather, capacity outlook will be adjusted accordingly

Winter Temperature & Precipitation Probability





Winter Outlook, cont.

- Winter Demand Forecast
  - 50/50 winter peak demand forecast of 20,166 MW, which is 310 MW (1.5%) lower than the 2019-20 forecast
  - 90/10 winter peak demand forecast of 20,806 MW, which is 367 MW (1.7%) lower than the 2019-20 forecast
  - Unknown societal factors will likely continue to exist and impact demand throughout this winter; forecasting staff is continuously evaluating load trends and retraining forecasting models frequently
- Scheduled Generation and Transmission Outages
  - All generation and transmission outages continue to be coordinated to minimize adverse transmission or capacity conditions
  - Very few pandemic-related outage cancellations or reschedules are anticipated
- Transfer Capability
  - Transfer capability on the New York Northern AC ties is expected to be increased from 1,400 MW to 1,500 MW for the winter period

Winter Preparations 2020-2021

- Winter Readiness Seminar
  - ISO hosted a WebEx Generator Winter Readiness Seminar with Market Participants on October 29, 2020
- Winter Generator Readiness Survey
  - Distributed a Winter Generator Readiness Survey to all generating resources in the region on October 29, 2020
  - Survey results will enhance ISO-NE's understanding of:
    - Winter preparations undertaken by the resources across the region
    - Temperature-specific limitations on a resource's real-time capabilities
    - Specific protocols followed in the event of extreme cold weather events
- Continue to perform a weekly 21-day look-ahead of forecasted conditions, thus providing an opportunity for generators to take action in advance of an Energy Emergency
- In addition to the Winter Generator Readiness Survey, the annual Natural-Gas Critical Infrastructure Survey process was incorporated into OP-21 prior to this winter

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (+0.8°F) Max: 78°F, Min: 28°F Precipitation: 1.00" – Above Normal Normal: 3.94"	Hartford	Temperature: Above Normal (+2.0°F) Max: 79°F, Min: 21°F Precipitation: 1.70" - Above Normal Normal: 4.37"

Peak Load:	15,501 MW	Oct, 30 2020	19:00 (ending)

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

Procedure	Declared	Cancelled	Note
M/LCC 2	10/29/2020 15:00	10/30/2020 16:00	Reason: Severe Weather

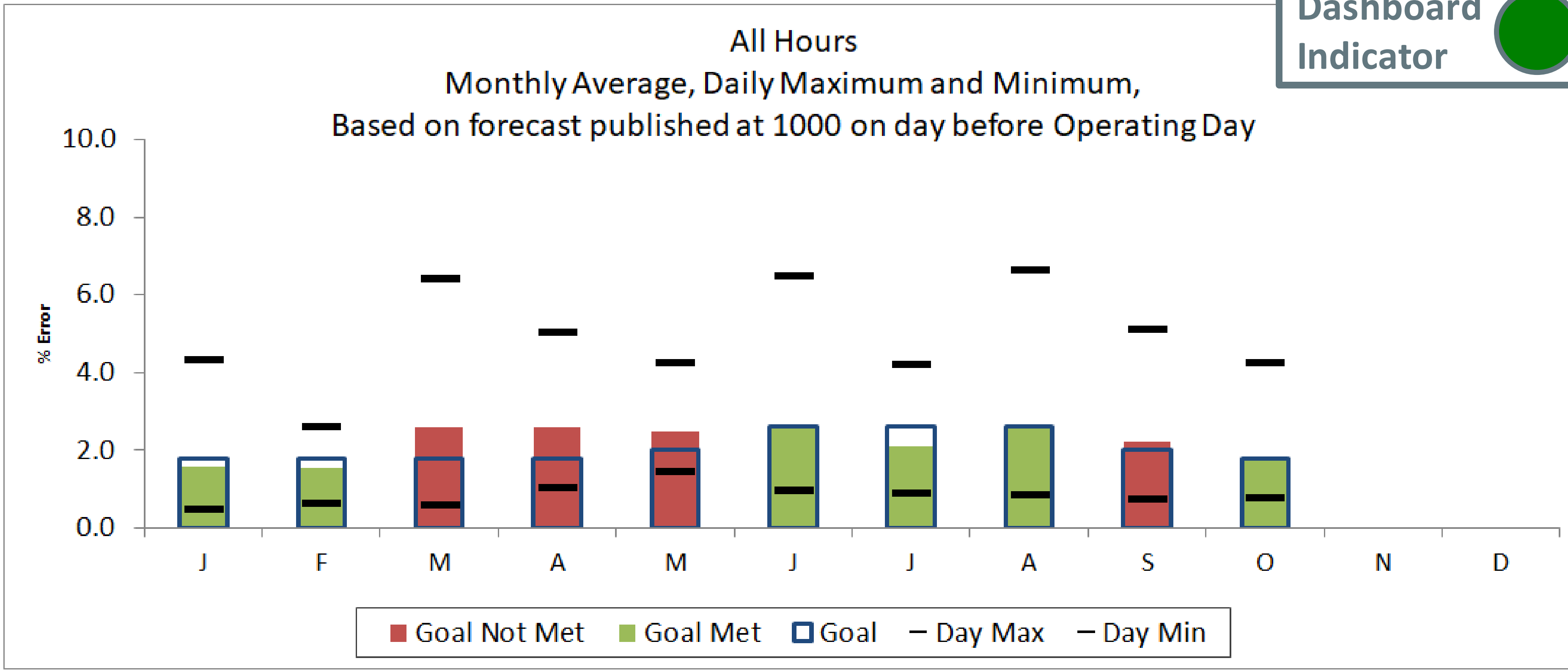
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
10/10/2020	NBPSO	385
10/12/2020	PJM	1160

2020 System Operations - Load Forecast Accuracy

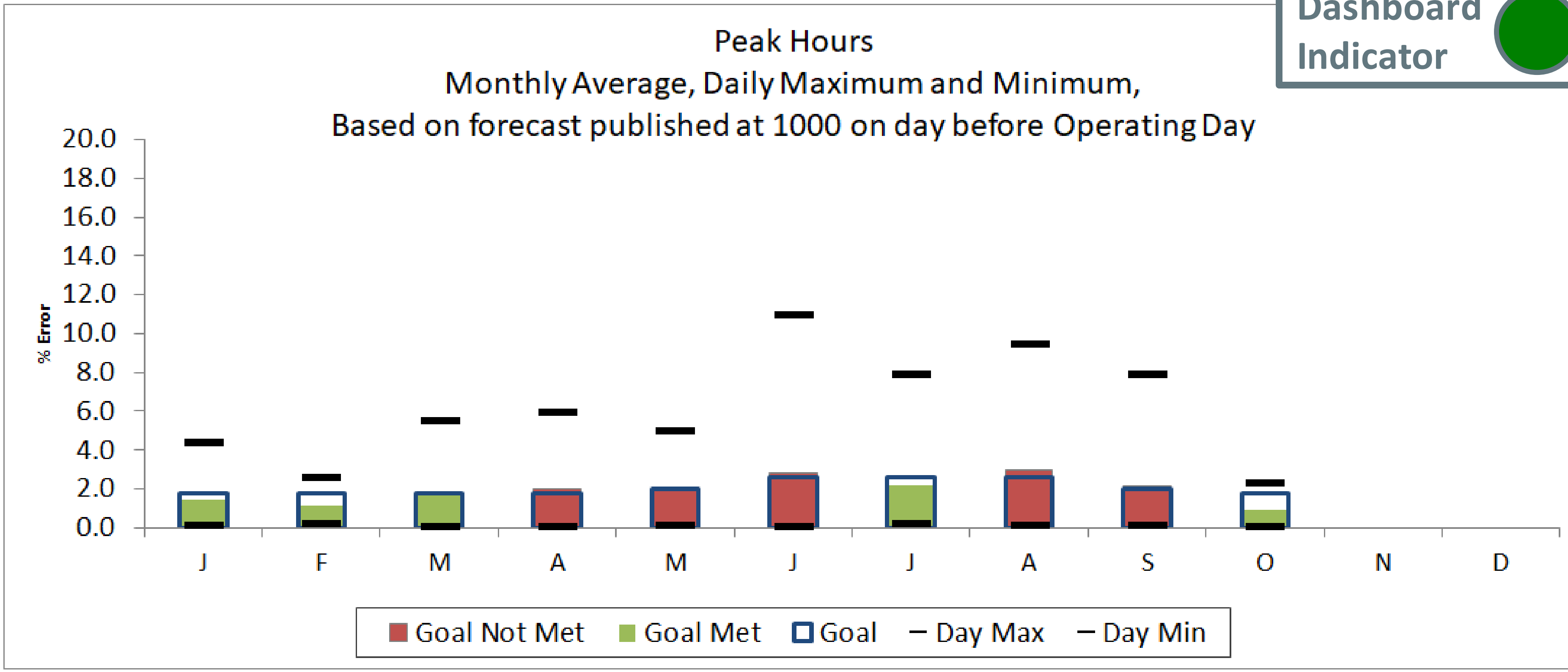
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.31	2.59	6.40	5.00	4.22	6.47	4.18	6.63	5.09	4.22			6.63
Day Min	0.46	0.61	0.58	1.03	1.42	0.96	0.88	0.84	0.72	0.75			0.46
MAPE	1.57	1.54	2.60	2.58	2.49	2.58	2.10	2.56	2.22	1.76			2.20
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80			

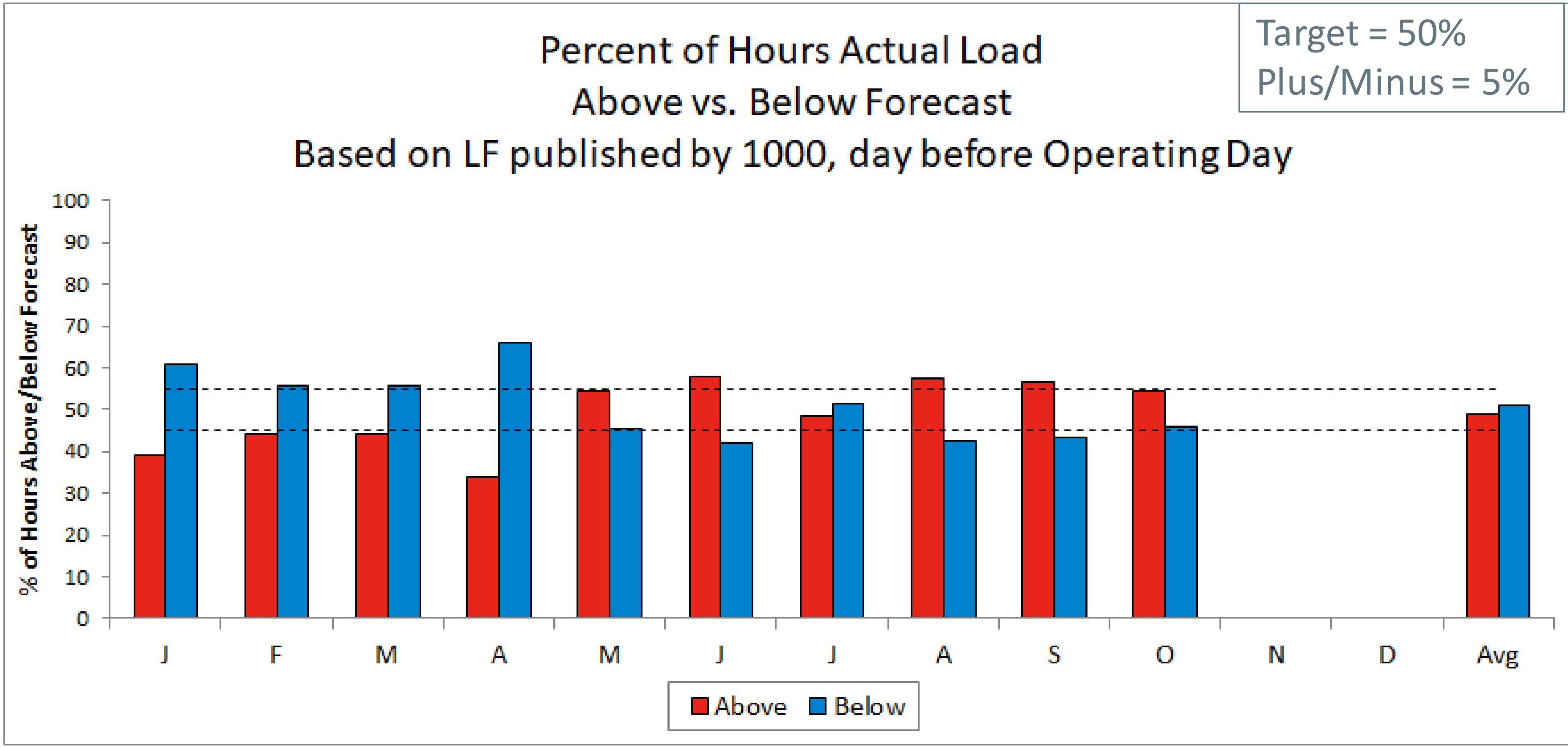
2020 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



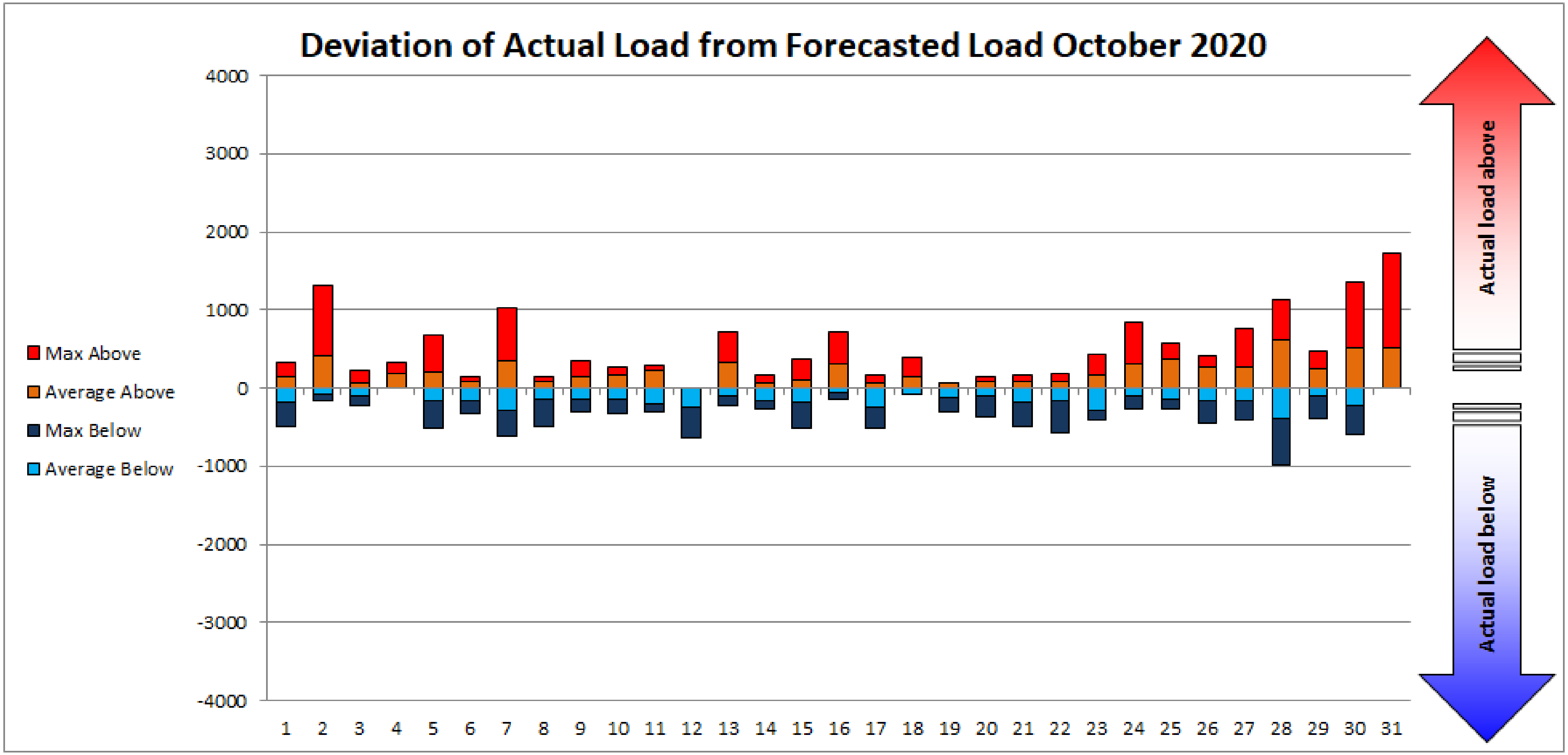
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.33	2.59	5.48	5.93	4.94	10.93	7.84	9.44	7.88	2.25			10.93
Day Min	0.07	0.19	0.01	0.00	0.13	0.05	0.14	0.07	0.10	0.00			0.00
MAPE	1.41	1.12	1.72	1.97	2.11	2.83	2.18	2.97	2.17	0.95			1.94
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80			

2020 System Operations - Load Forecast Accuracy cont.

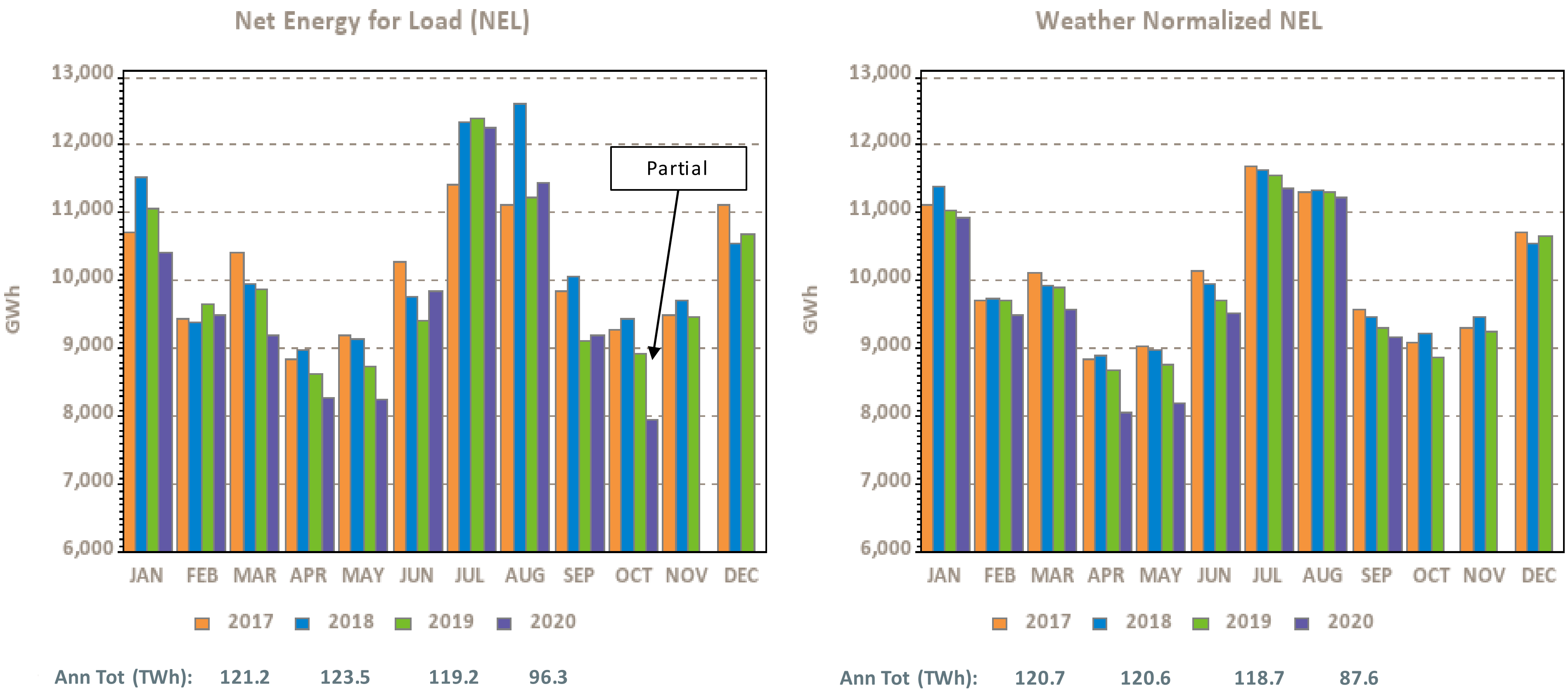


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	39	44.3	44.4	33.9	54.4	57.9	48.4	57.6	56.5	54.3			49
Below %	61	55.7	55.6	66.1	45.6	42.1	51.6	42.4	43.5	45.7			51
Avg Above	136.2	169.9	207	178.9	231.9	257.5	248.3	287.2	255.5	215.2			287
Avg Below	-192.4	-157.6	-263.9	-265.3	-196.3	-243.5	-281.7	-245.5	-166.6	-156.9			-282
Avg All	-65	-13	-56	-106	38	22	-26	73	89	52			1

2020 System Operations - Load Forecast Accuracy cont.

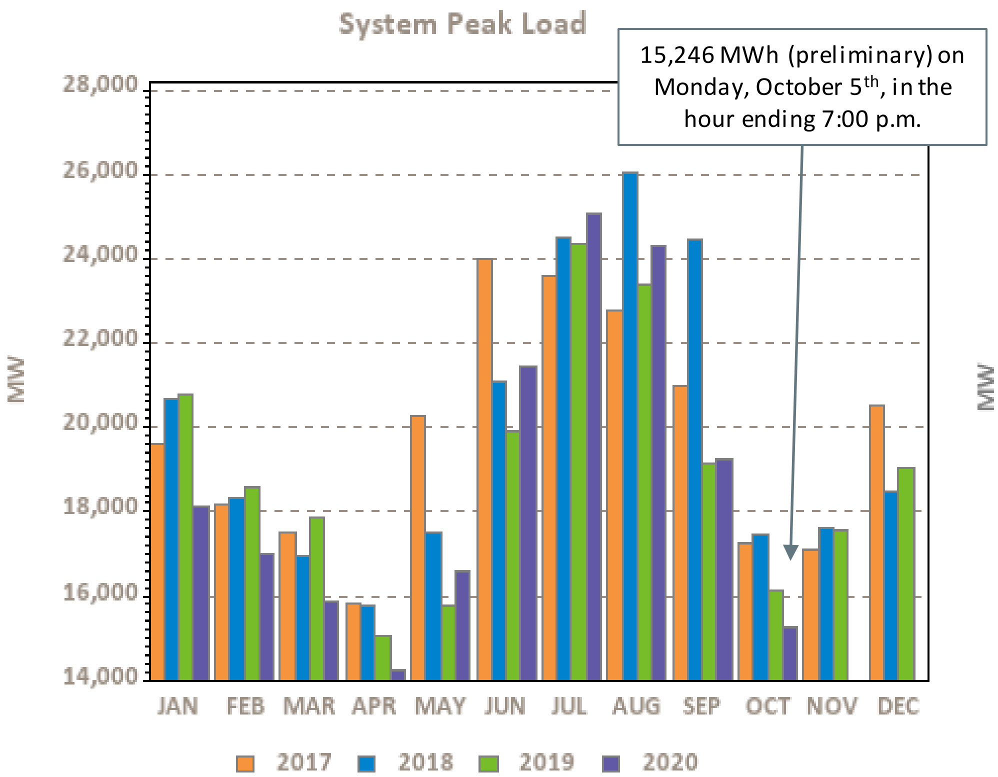


Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL

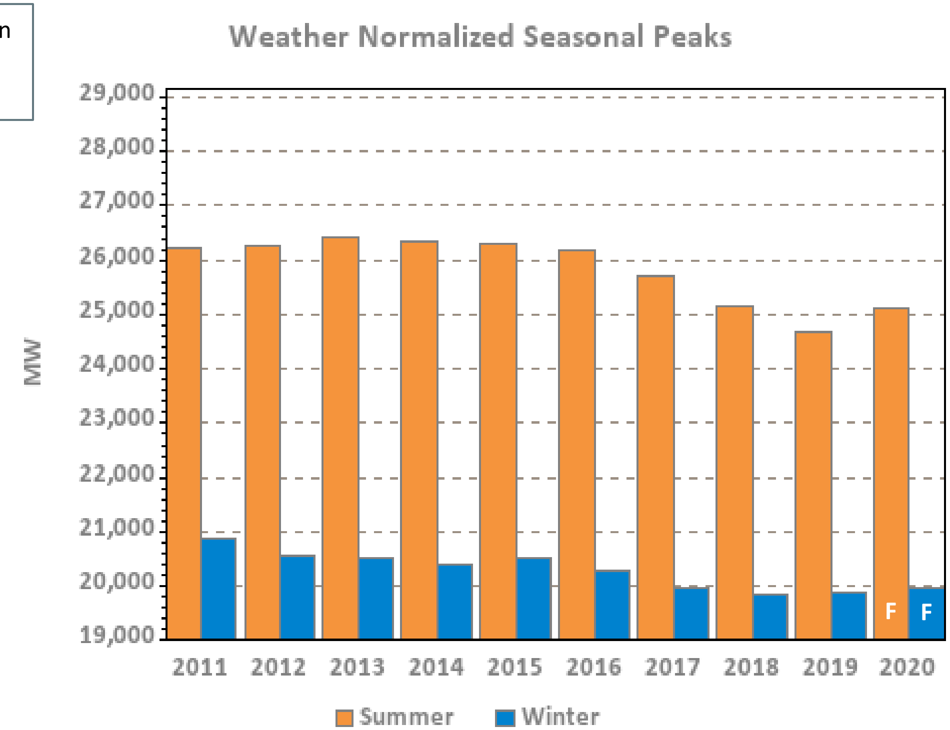


NEPOOL NEL is the total net revenue quality metered energy required to serve load and is analogous to 'RT system load.' NEL is calculated as: Generation – pumping load + net interchange where imports are positively signed. Current month's data may be preliminary. Weather normalized NEL may be reported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

Monthly Peak Loads and Weather Normalized Seasonal Peak History



Revenue quality metered value

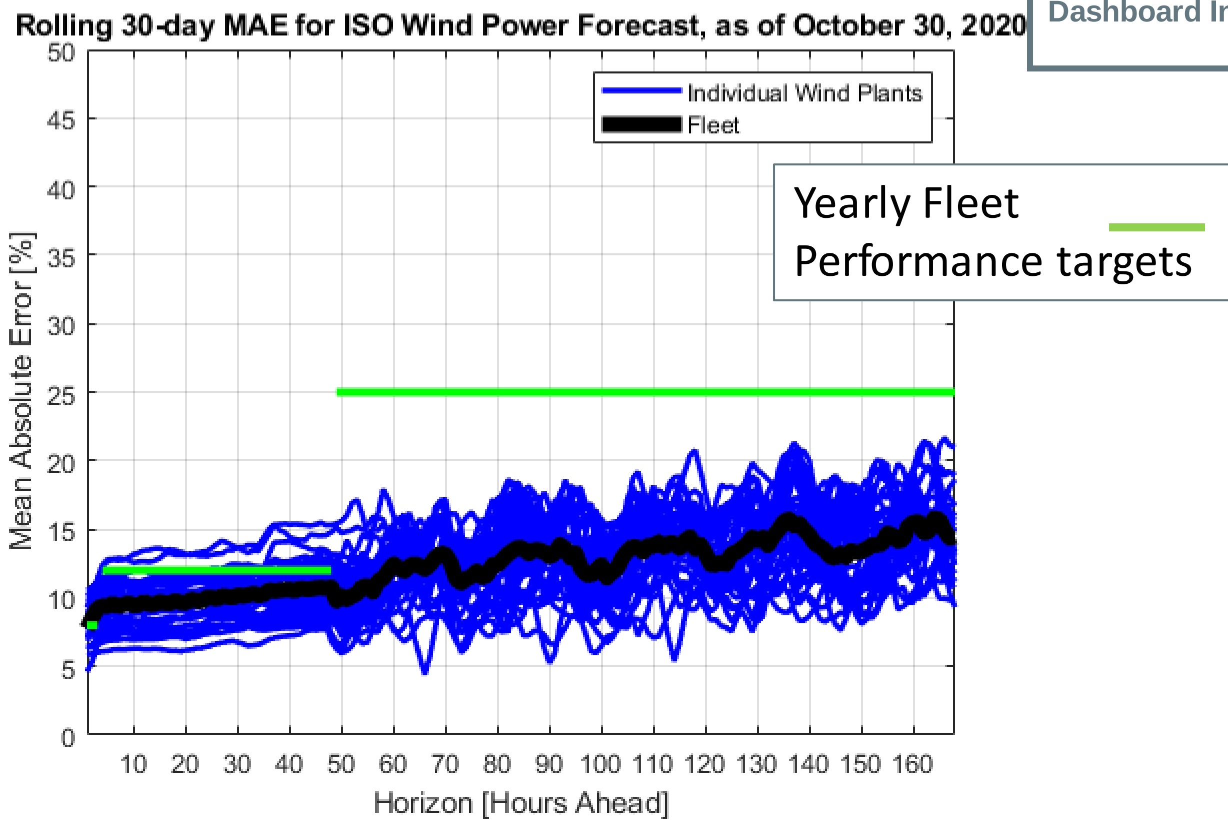


Winter beginning in year displayed

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

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

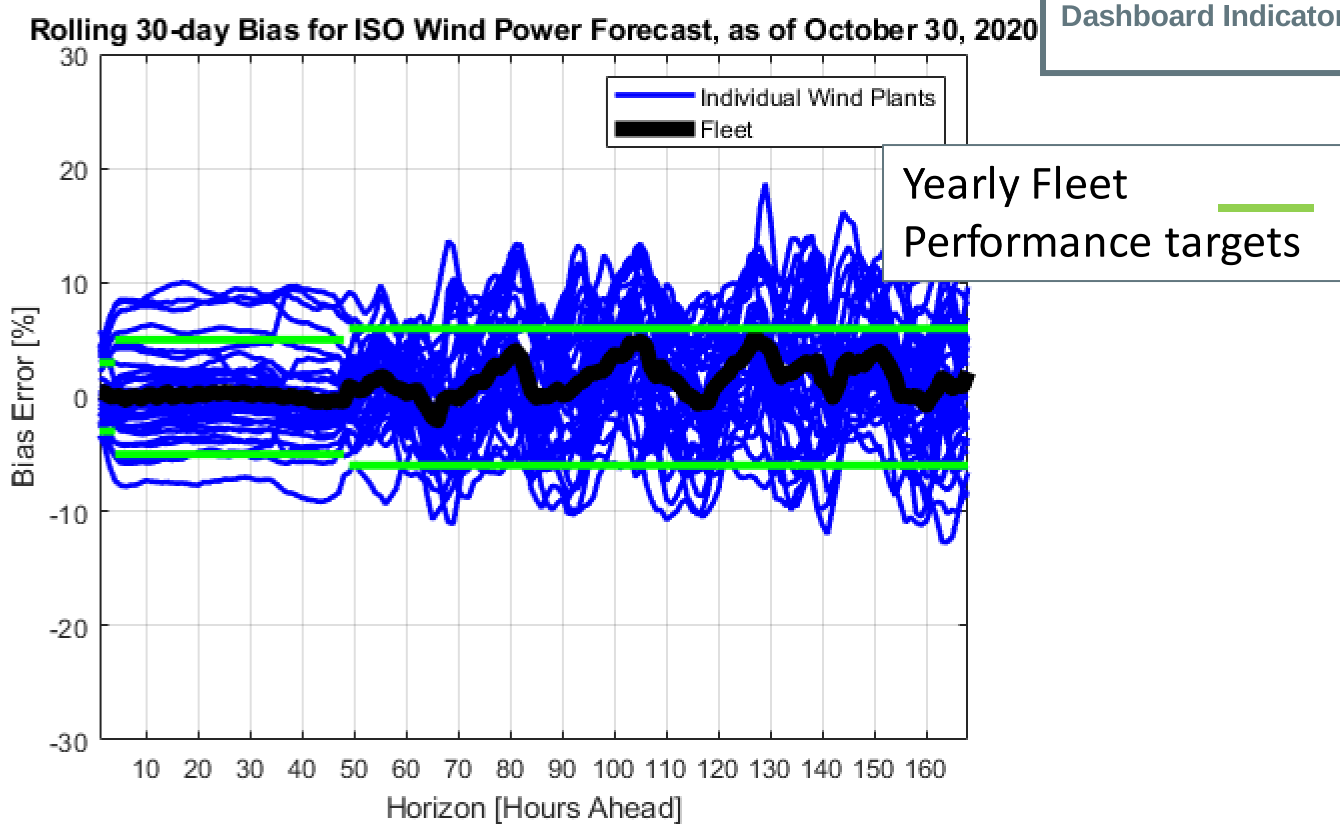
Dashboard Indicator



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

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

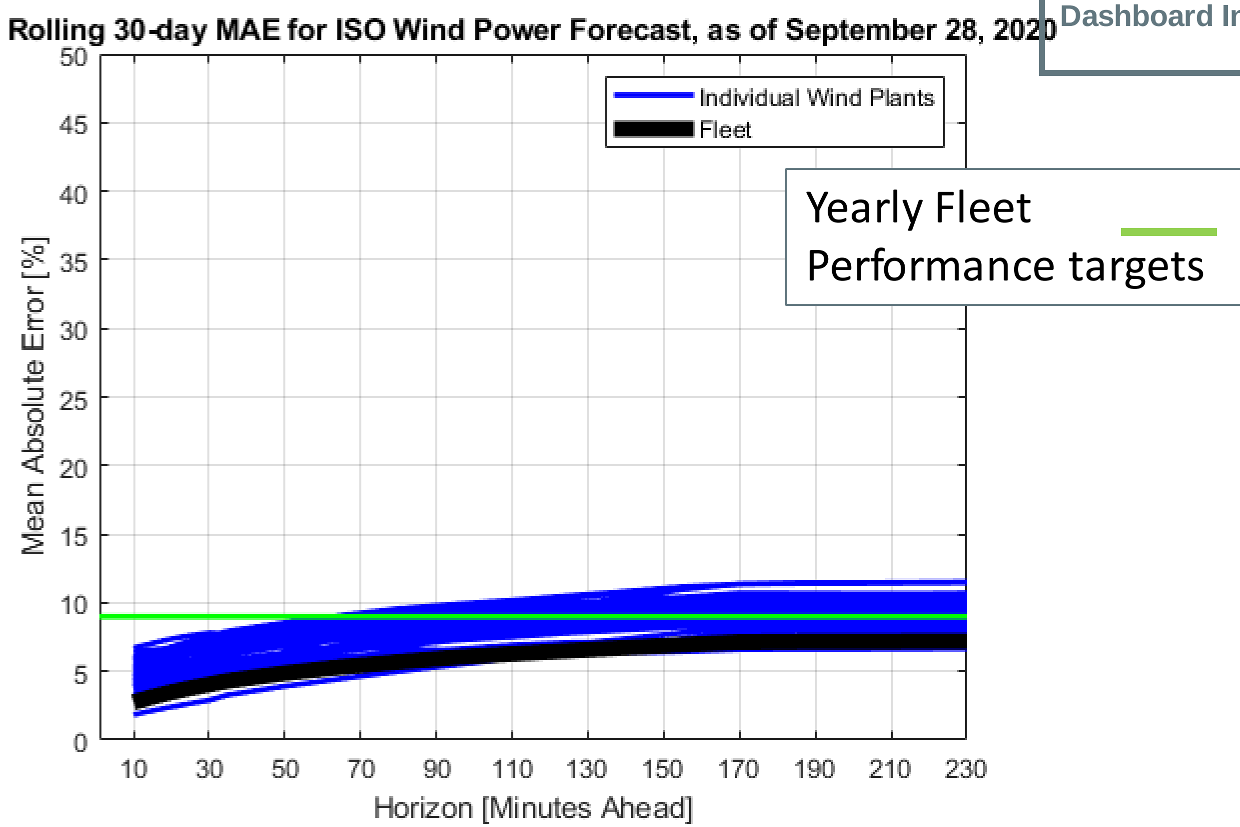
Dashboard Indicator



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

Wind Power Forecast Error Statistics: Short Term Forecast MAE

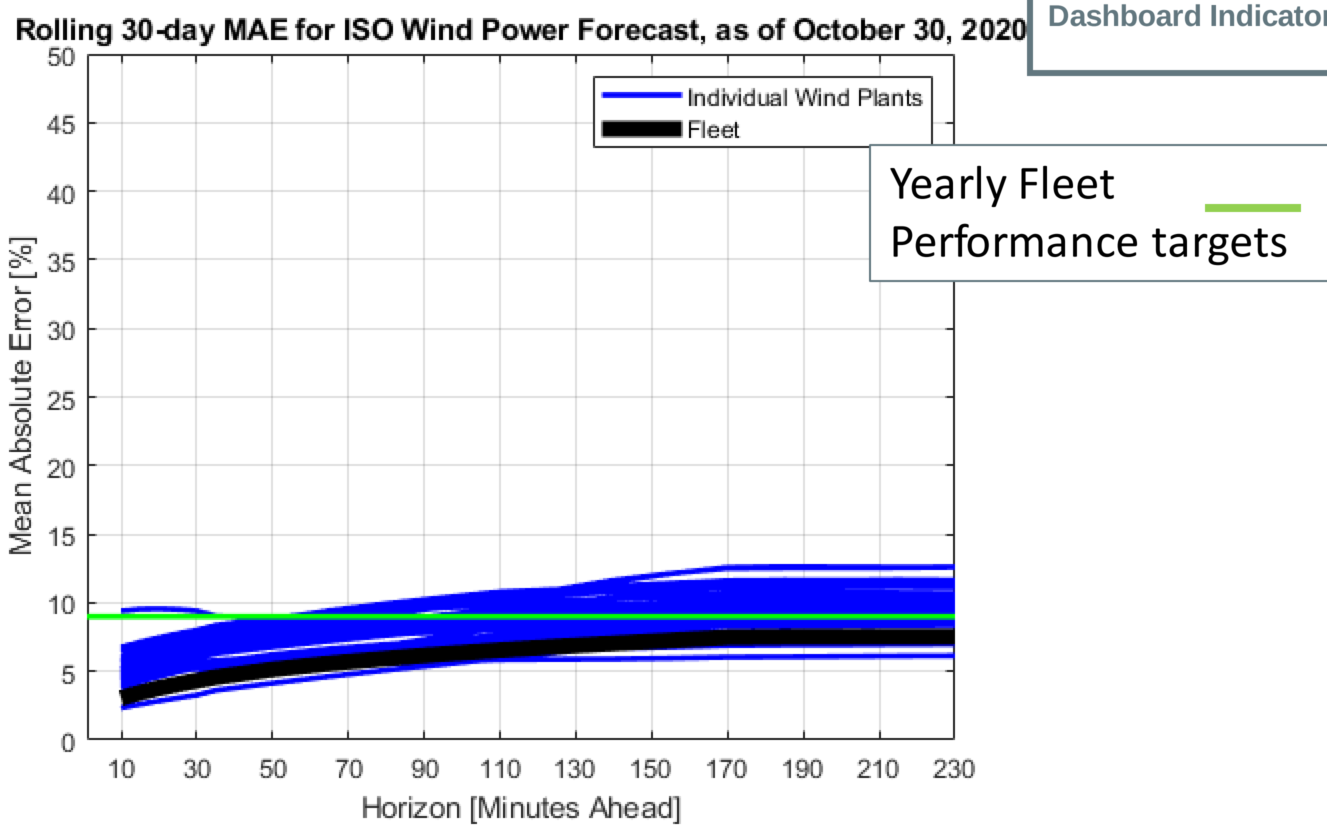
Dashboard Indicator



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

Wind Power Forecast Error Statistics: Short Term Forecast Bias

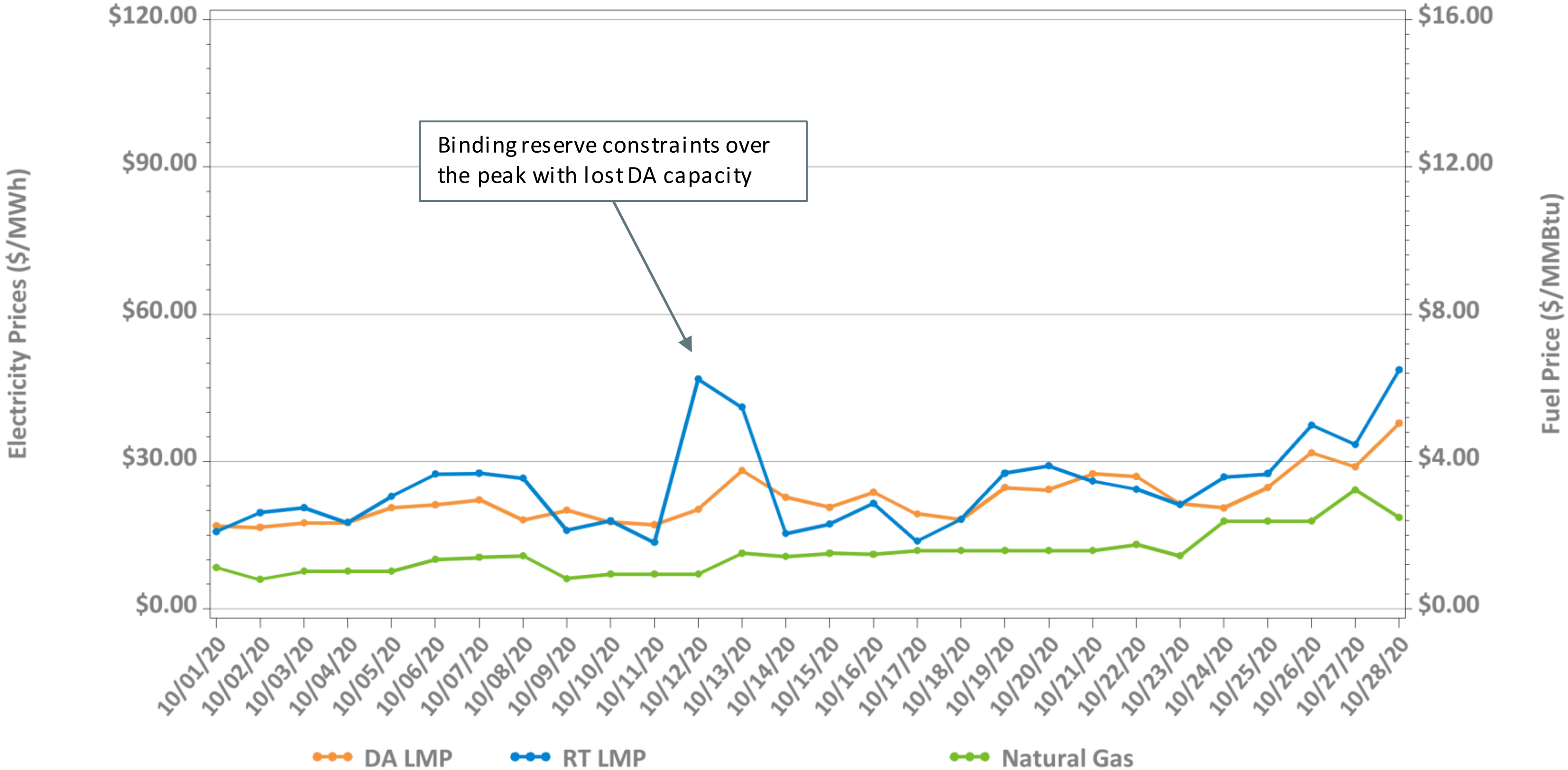
Dashboard Indicator



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

MARKET OPERATIONS

Daily Average DA and RT ISO-NE Hub Prices and Input Fuel Prices: October 1-28, 2020

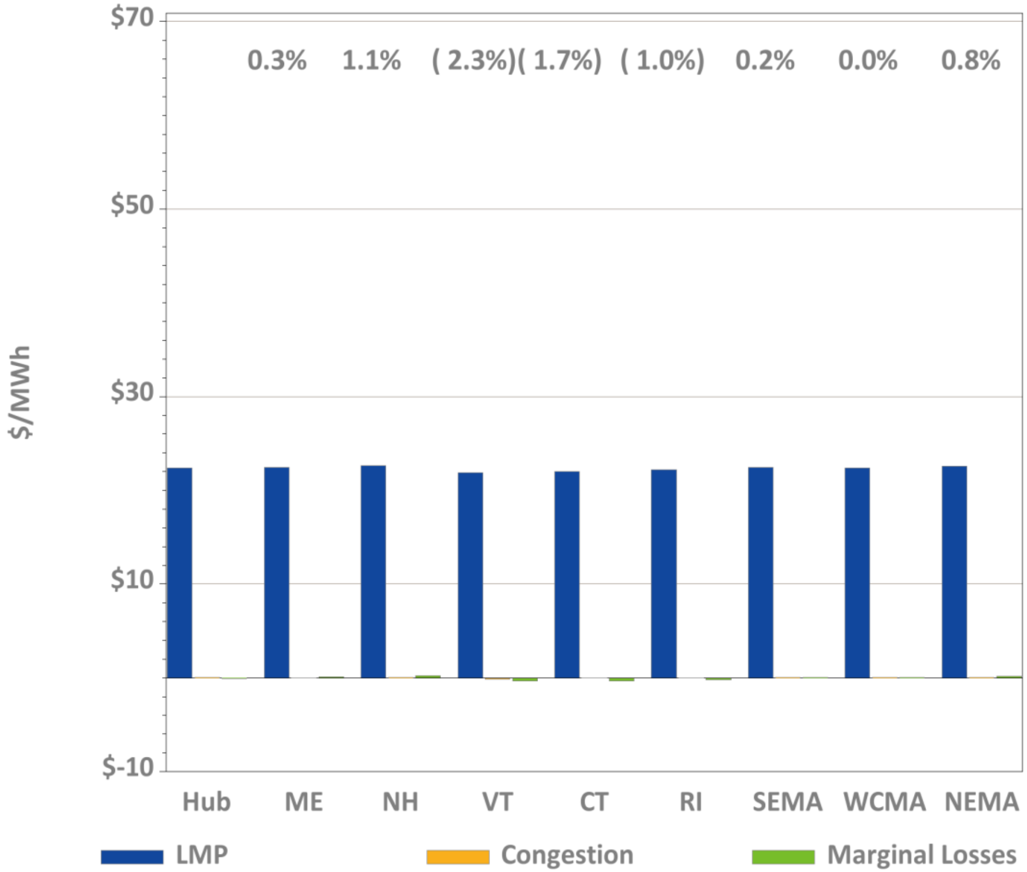


Underlying natural gas data furnished by:

ice Global markets in clear view

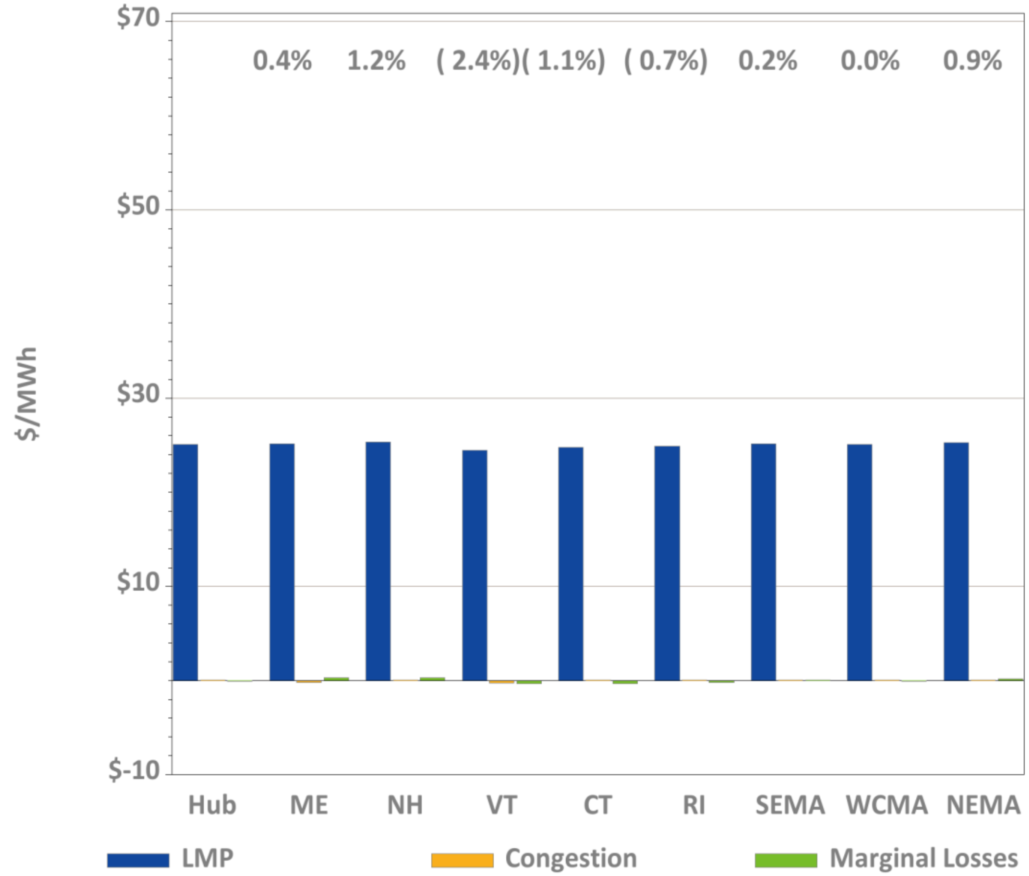
Average price difference over this period (DA-RT): $-2.67
Average price difference over this period ABS(DA-RT): $4.92
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 20%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, October 2020



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

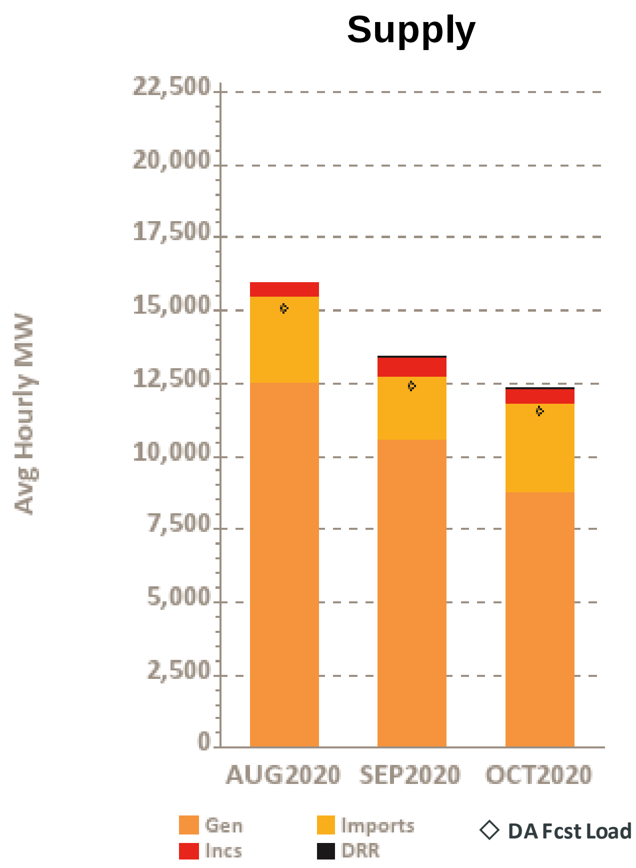
RT LMPs Average by Zone & Hub, October 2020

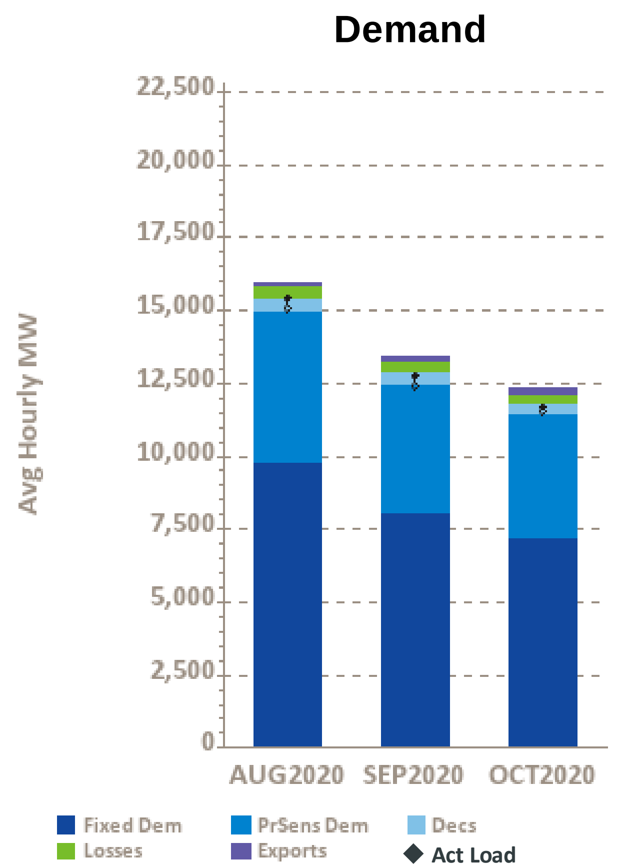


Definitions

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

Components of Cleared DA Supply and Demand – Last Three Months

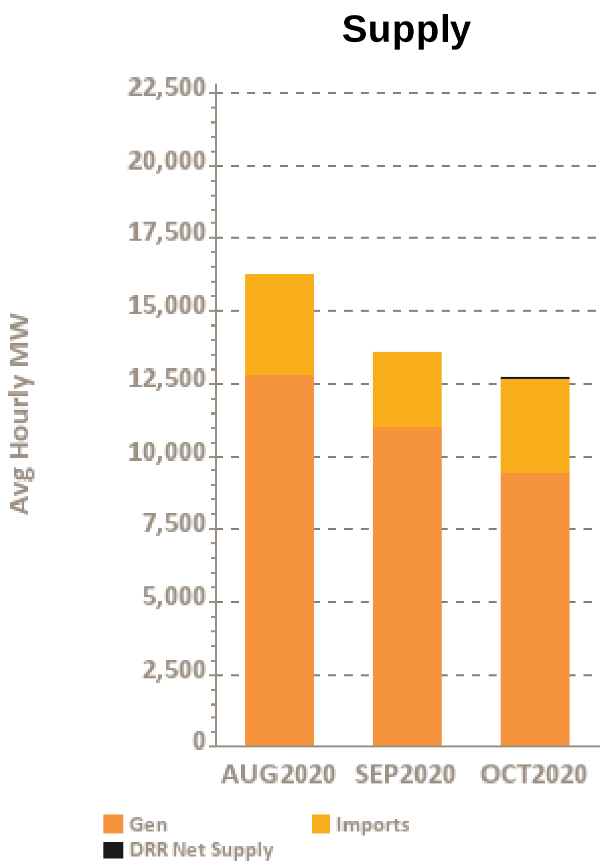


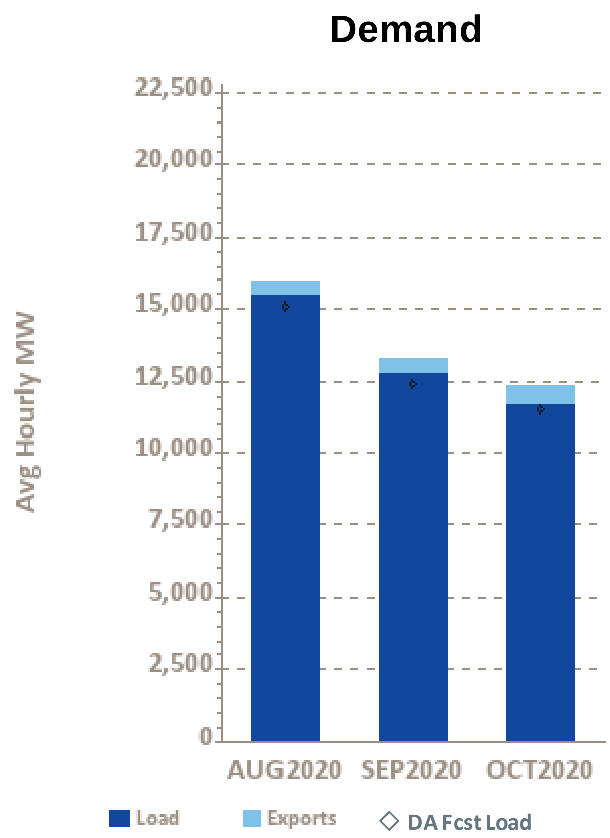


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load
DRR – Demand Response Resource

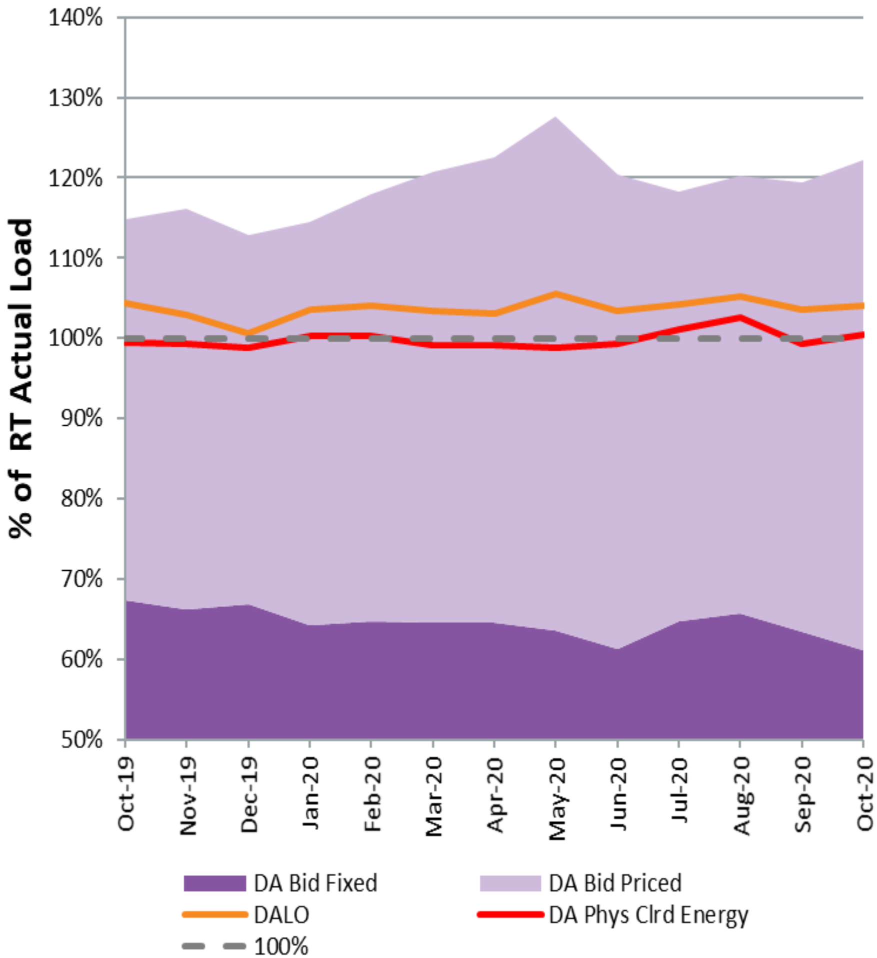
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

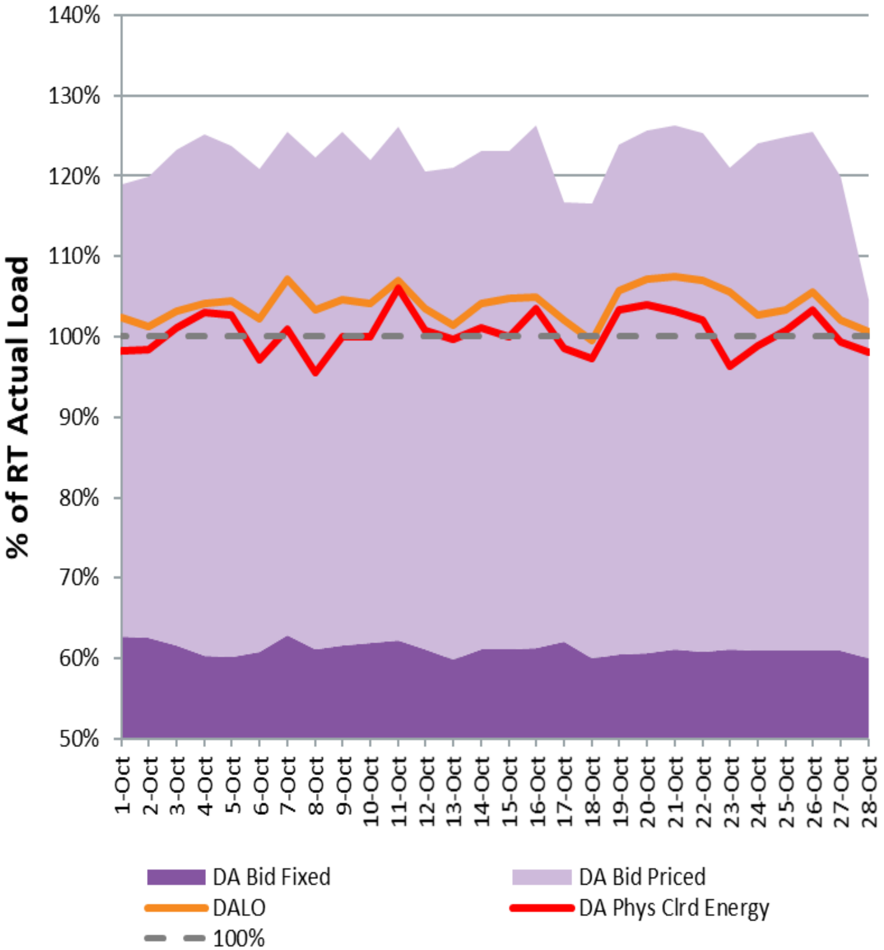
Components of RT Supply and Demand – Last Three Months





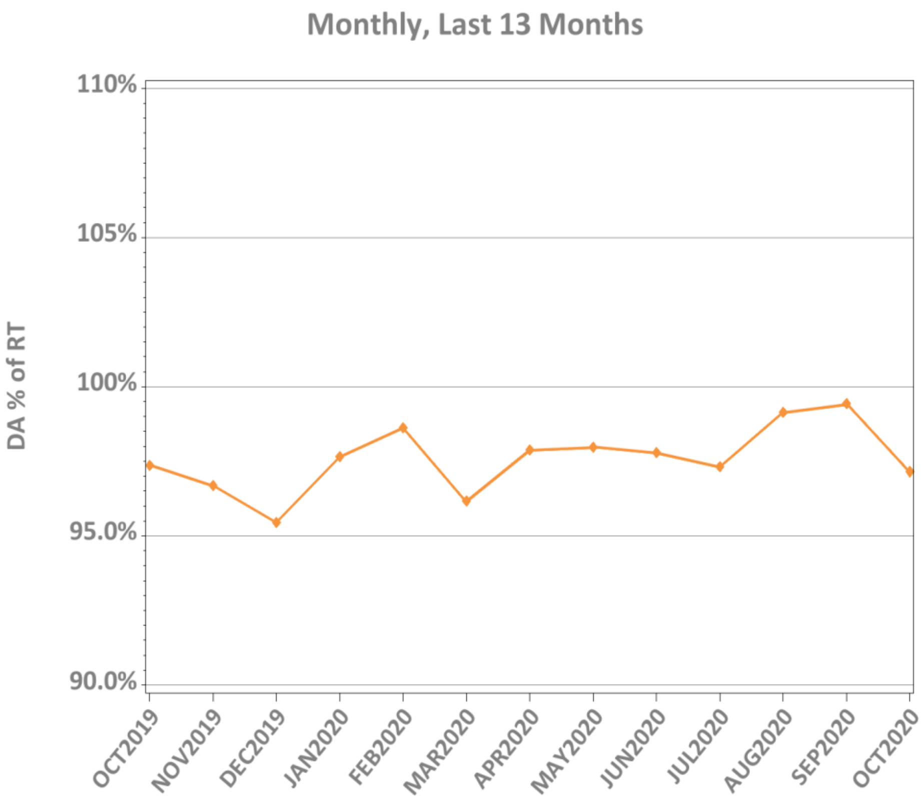
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

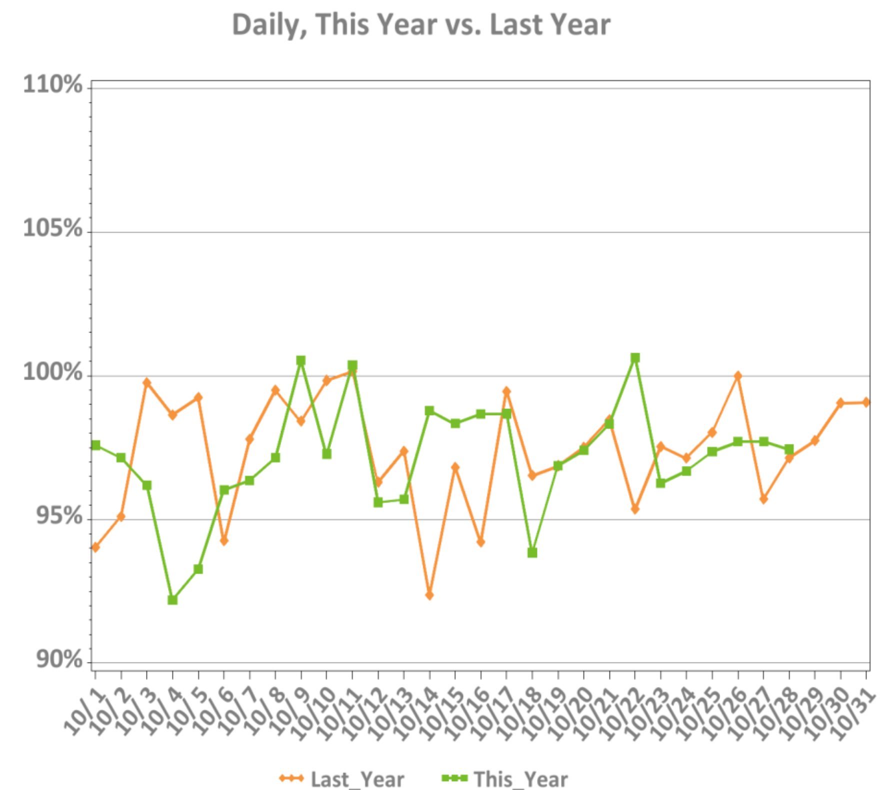




Note: Forecasted peak hour for each day is reflected in the above values. Shown for each day (chart on right) and then averaged for each month (chart on left). 'DA Bid' categories reflect load assets only (Virtual and export bids not reflected.)

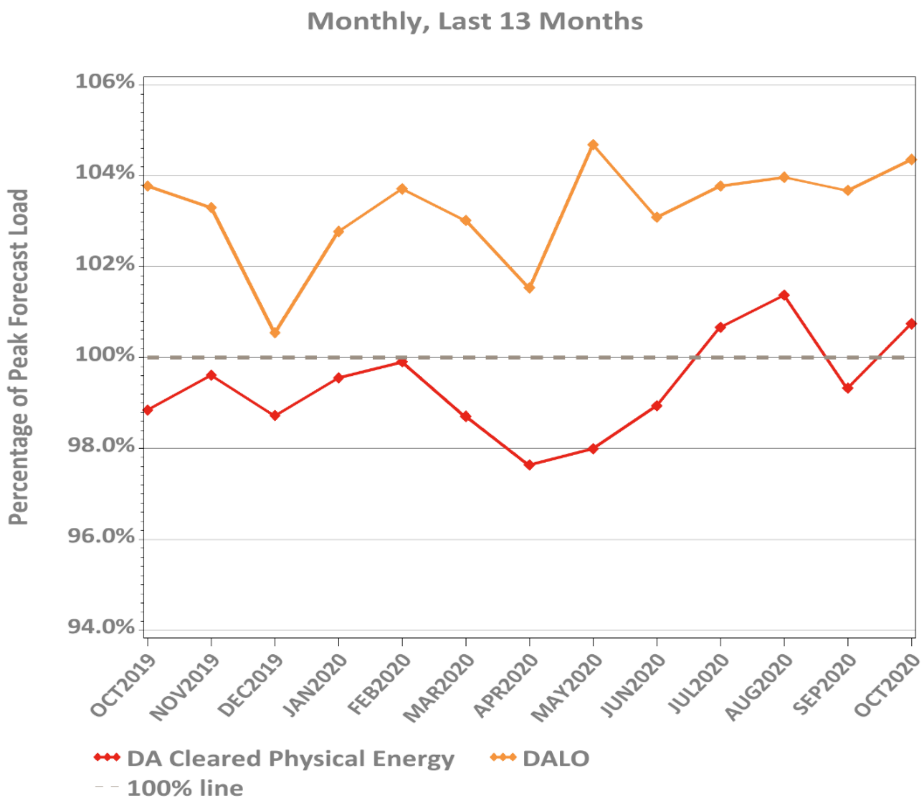
DA vs. RT Load Obligation: October, This Year vs. Last Year

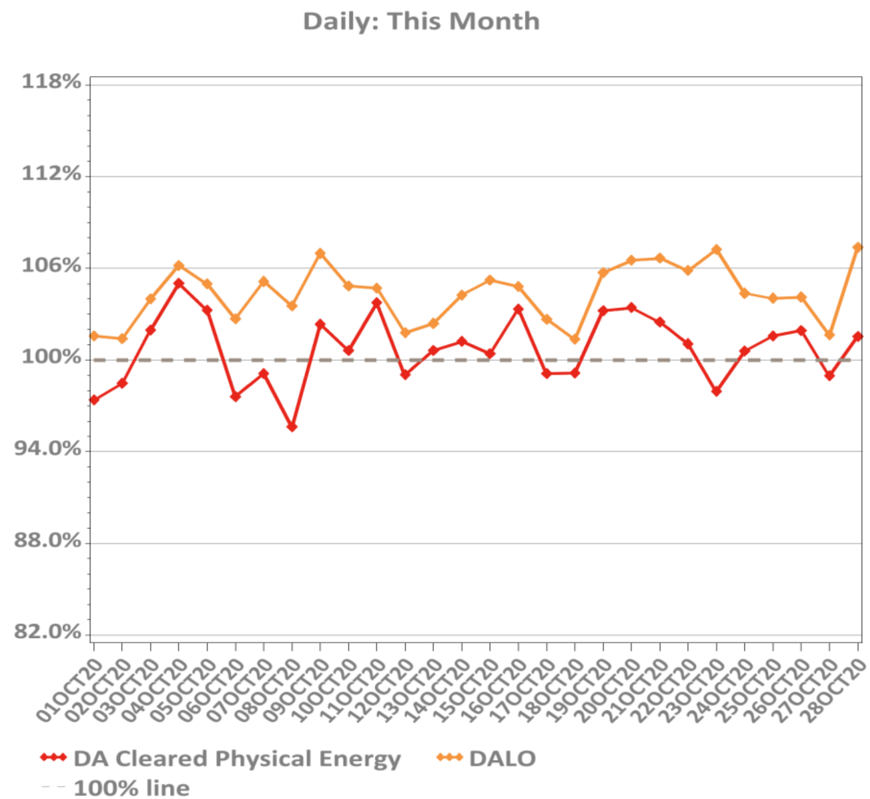




*Hourly average values

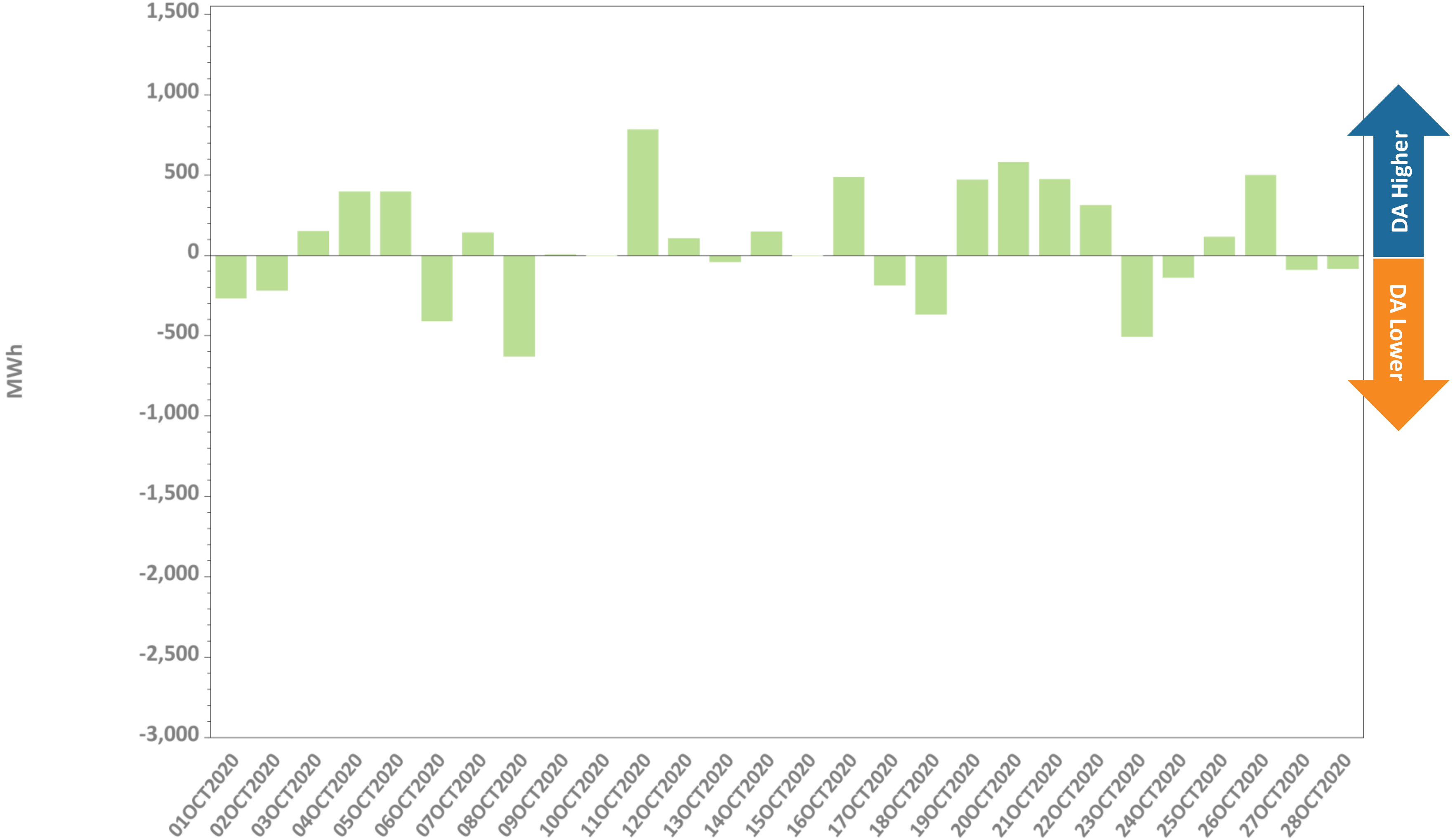
DA Volumes as % of Forecast in Peak Hour





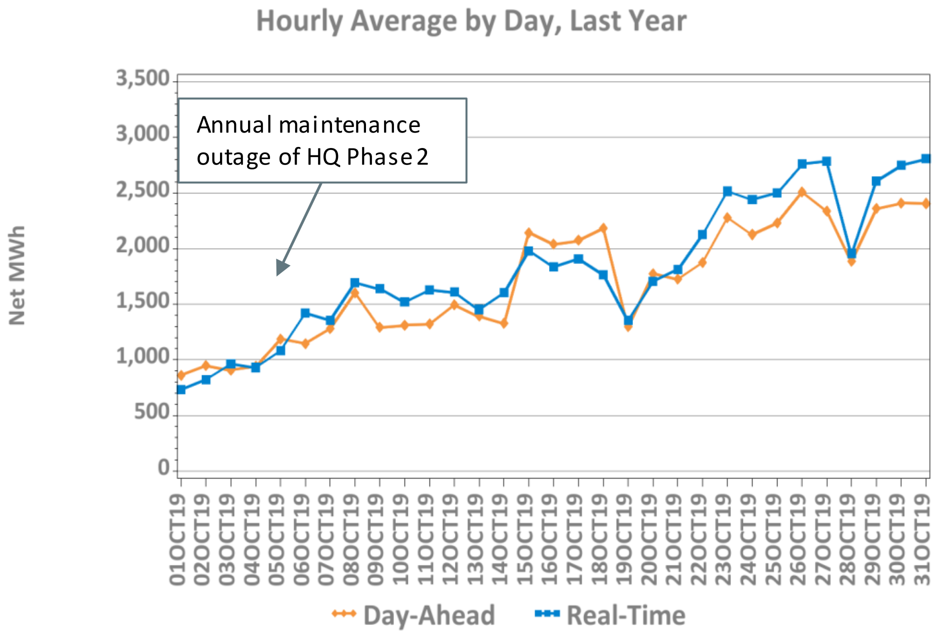
Note: There were **no** instances of system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) during October.

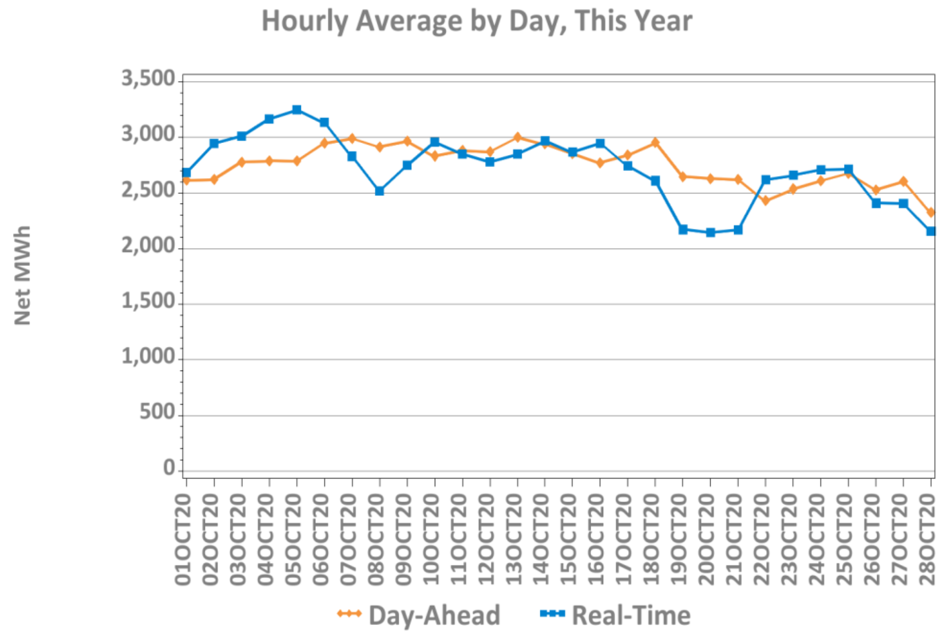
DA Cleared Physical Energy Difference from RT System Load at Peak Hour*



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

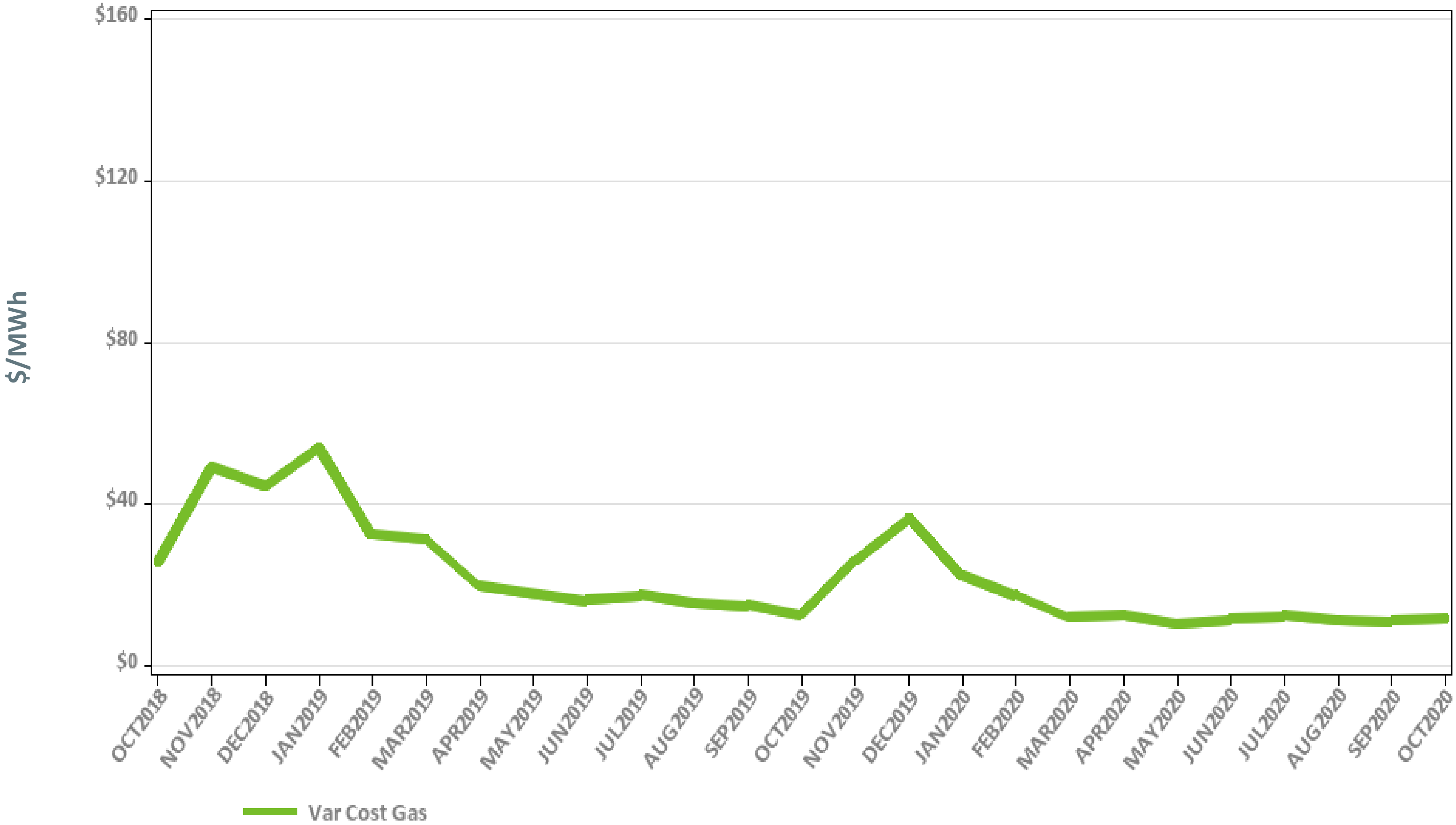
DA vs. RT Net Interchange October 2019 vs. October 2020





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

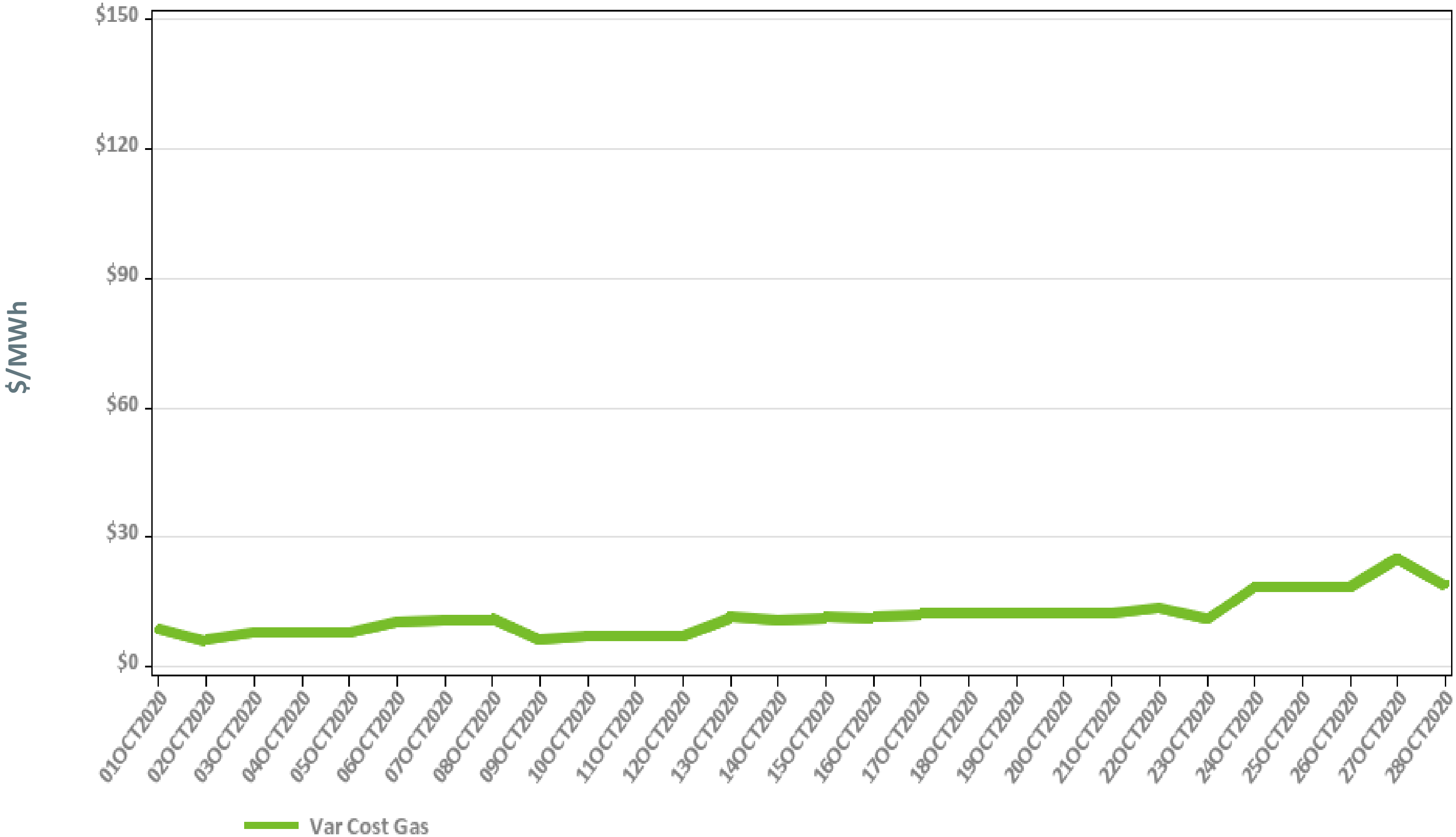


Underlying natural gas data furnished by:

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

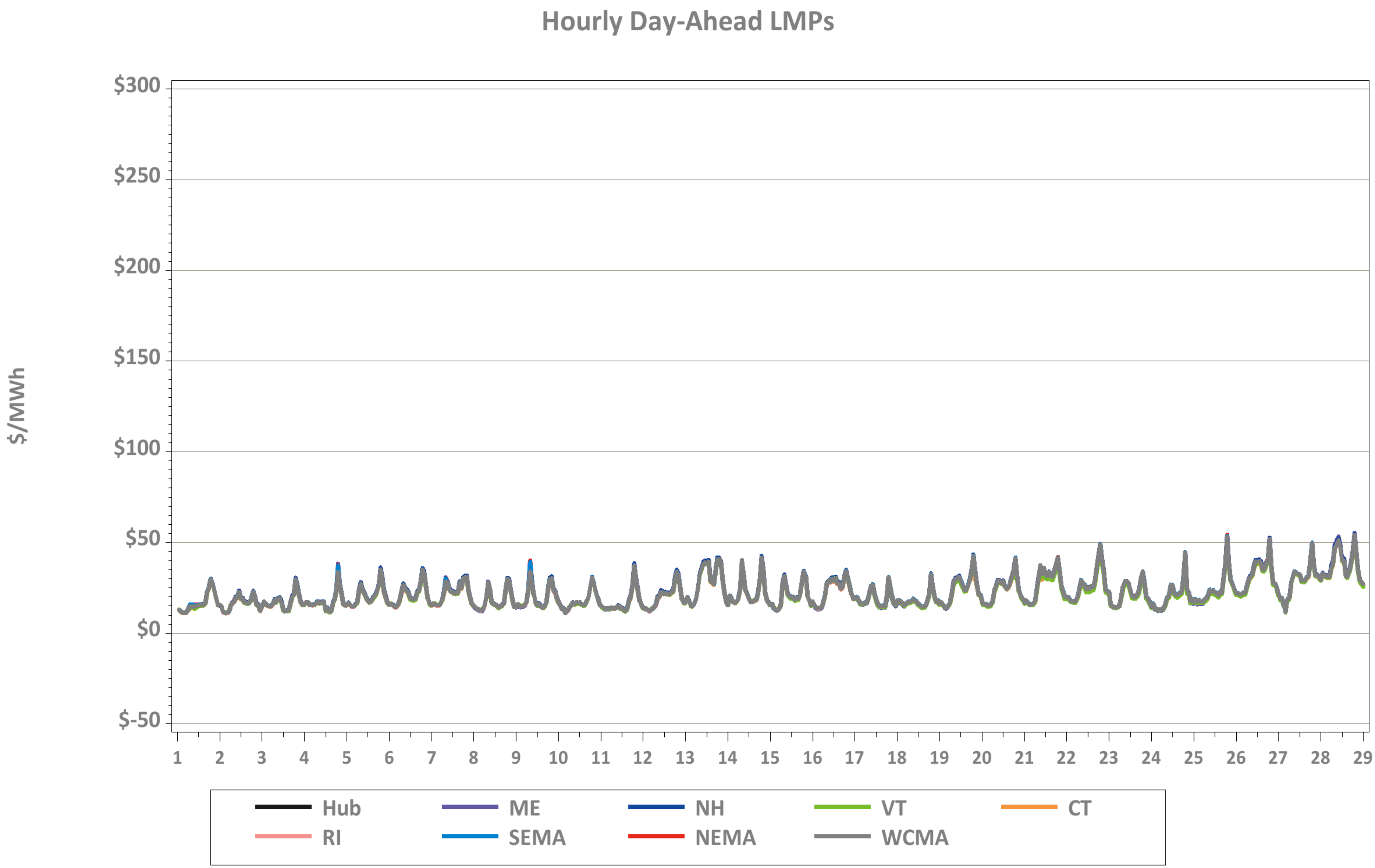


Underlying natural gas data furnished by:

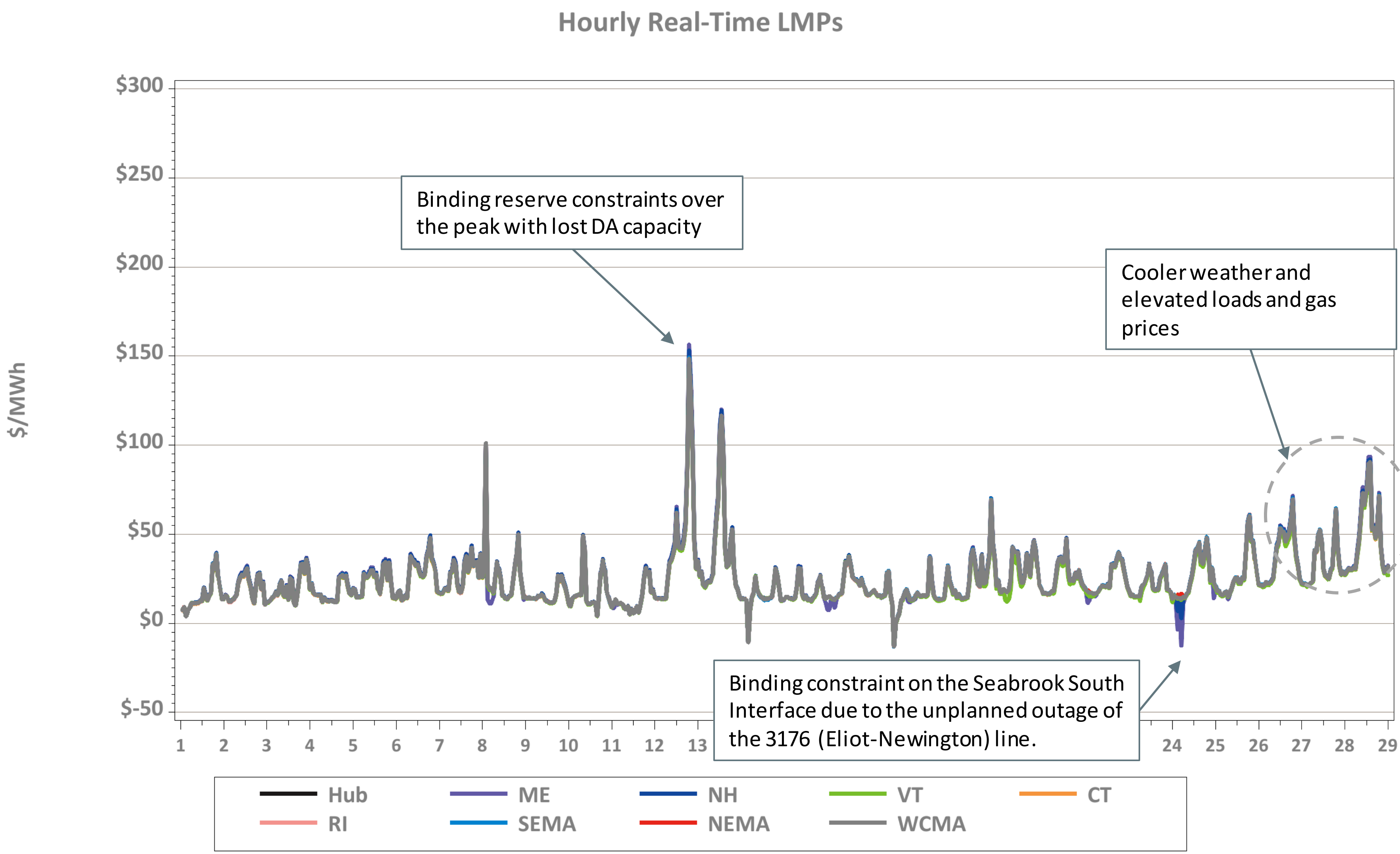
ICE Global markets in clear view

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

Hourly DA LMPs, October 1-28, 2020

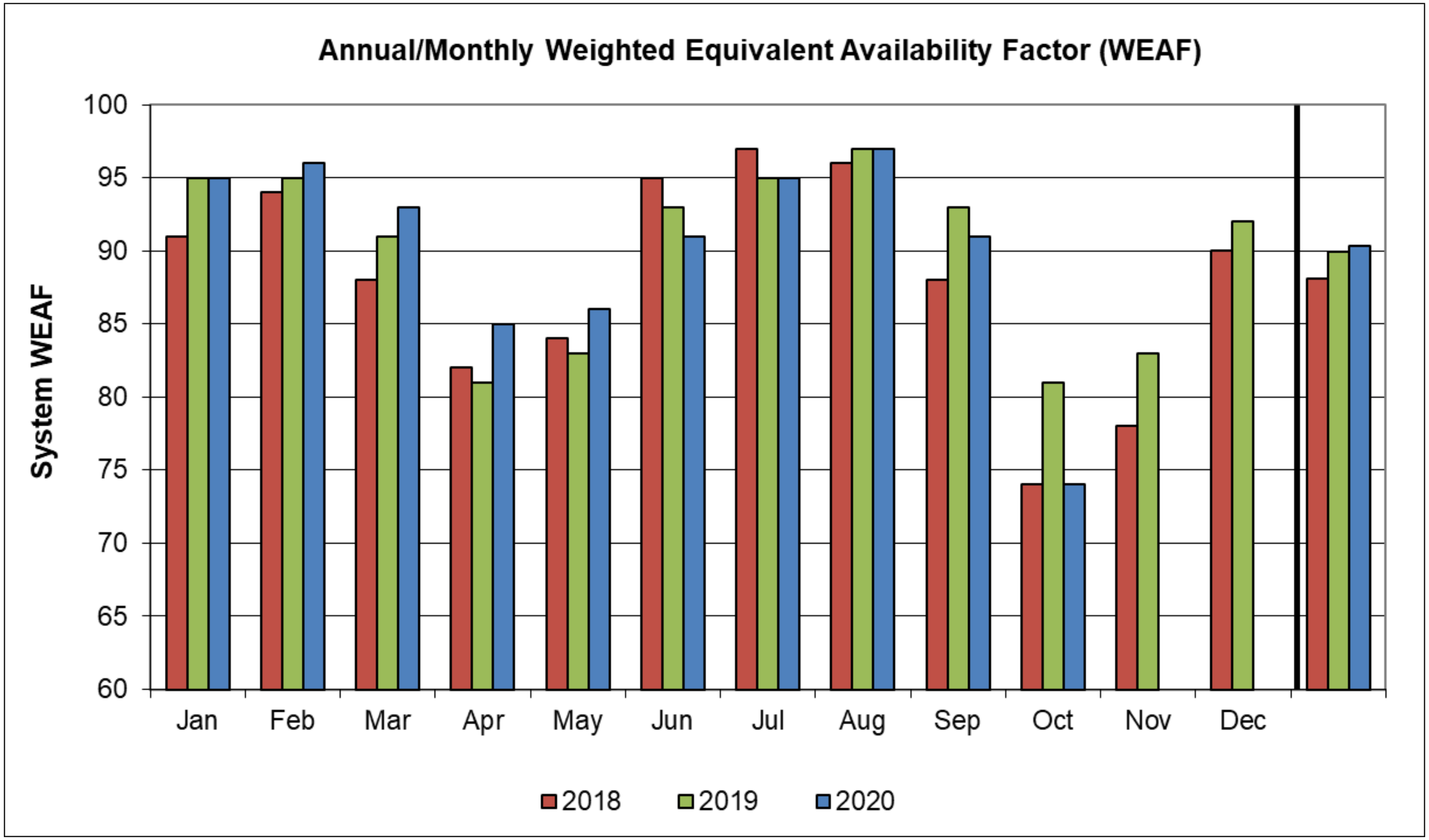


Hourly RT LMPs, October 1-28, 2020



- No Minimum Generation Emergencies were declared during October.

System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2020	95	96	93	85	86	91	95	97	91	74			90
2019	95	95	91	81	83	93	95	97	93	81	83	92	90
2018	91	94	88	82	84	95	97	96	88	74	78	90	88

Data as of 10/27/2020

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Paul Belval, NEPOOL Counsel

DATE: October 29, 2020

RE: "Know Your Customer" Changes to ISO-NE Financial Assurance Policy

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At its November 5, 2020 meeting, the Participants Committee will be asked to consider changes to "Know Your Customer" disclosures required in the ISO New England Financial Assurance Policy ("FAP"). The changes were proposed by the ISO as part of an industry-wide review of RTO disclosure requirements and are intended to improve the level of disclosure that Market Participants and applicants to become Market Participants are required to make. The proposed changes are included in Attachment 1 to this memorandum, and this memorandum summarizes those changes.

The FAP changes add the form currently used for annual Market Participation Information Disclosure to the FAP as an attachment and make several changes to that form. Among the more significant changes are:

- Several of the required disclosures were expanded from only the Market Participant or applicant and Principals to include predecessors, and certain personnel with decision-making responsibility in the New England Markets or ability to enter transactions in ISO systems, and to ask about their previous activities in relevant markets;
- In certain questions, disclosures about market activity were expanded from the United States to include all North American energy markets and trading exchanges and in other questions, expanded to domestic or international energy markets and trading exchanges;
- In addition to disclosures regarding material litigation and sanctions, a question was added to require disclosure of known material ongoing investigations;
- The disclosure period was expanded from five to ten years for most items (and two new requirements were limited to five years);
- Questions were added regarding revocation of participation in another RTO, and for new applicants, plans for funding activities in the New England Markets;
- Language was added giving the ISO the ability to request additional information about risk management functions, specifically segregation of duties (including organizational charts or equivalent information); and
- Other clarifying changes were made to the questions (e.g., specifying what information needs to be provided about a bankruptcy and clarifying the standard for disclosure of litigation and sanctions).

Market Participants and applicants are not required to disclose information if that disclosure would be prohibited by law, but they are required to use reasonable efforts to obtain permission to make that disclosure. The ISO, after review of the information provided in the form, may require additional information from the Market Participant or applicant.[1]

Finally, the changes to the FAP include adding language requiring that an applicant with a previous uncured payment default cure that default before becoming a Market Participant again. That language also permits the ISO to determine whether an entity seeking to participate in the New England Markets under a different name, affiliate or organization should be treated as the same entity that had the previous payment default. Applicants are not required to cure payment defaults that have been discharged under the U.S. Bankruptcy Code.

The Know Your Customer changes to the FAP were discussed by the Budget and Finance Subcommittee (the "Subcommittee") at its March 26, 2020, April 21, 2020 and May 14, 2020 teleconferences. These changes to the FAP were initially on the agenda for the June 4, 2020 Participants Committee meeting, but the changes, together with certain clean-up changes to the FAP, were removed from the agenda shortly before the meeting because several Participants Committee members requested additional time to review and provide feedback on the changes. The ISO made further revisions to the Know Your Customer changes to the FAP, which were discussed by the Subcommittee at its August 21, 2020 and October 5, 2020 teleconferences. There were no objections or comments on the version of the Know Your Customer changes to the FAP discussed by the Subcommittee on October 5, which is the version attached to this memorandum.

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

> RESOLVED, that the Participants Committee supports the Know Your Customer revisions to the ISO New England Financial Assurance Policy, as proposed by the ISO and as circulated to this Committee with the October 29, 2020 supplemental notice, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair of the Budget and Finance Subcommittee.

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[1] As provided currently in the FAP, if the ISO determines that the participation of a Market Participant or applicant presents an unreasonable risk to the New England Markets, the ISO shall request the input of the Participants Committee on the suspension or termination of a Market Participant or rejection of the applicant's application or other conditions to mitigate that risk. If the ISO chooses to reject (in the case of an applicant) or terminate (in the case of a Market Participant), the ISO must obtain FERC approval before taking that action.

EXHIBIT IA

ISO NEW ENGLAND FINANCIAL ASSURANCE POLICY

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under the ISO New England Financial Assurance Policy will be credited to the account of the group member with the customer identification at the ISO.

II. MARKET PARTICIPANTS' REVIEW AND CREDIT LIMITS

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

A. Minimum Criteria for Market Participation

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

1. Information Disclosure

(a) Each customer and applicant, on an annual basis (by April 30 each year) shall submit a completed information form in the form of (with only minor, non-material changes) and with the information required by Attachment 6 to the ISO New England Financial Assurance Policy~~: (i) a list of Principals; (ii) a list of any material criminal or civil litigation involving the customer or applicant or any of the Principals of the customer or applicant arising out of participation in any U.S. wholesale or retail energy market in the past five years; (iii) a list of sanctions involving the customer or applicant or any of the Principals of the customer or applicant imposed by the Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Commodity Futures Trading Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets where such sanctions were~~

~~either imposed in the past five years or, if imposed prior to that, are still in effect; (iv) a written summary of any bankruptcy, dissolution, merger or acquisition of the customer or applicant in the preceding five years; and (v) a list of current retail and wholesale electricity markets-related operations in the United States, other than in the New England Markets~~. Customer or applicant shall not be required to disclose information required by Attachment 6 if such disclosure is prohibited by law; provided, however, if the disclosure of any information required by Attachment 6 is prohibited by law, then customer or applicant shall use reasonable efforts to obtain permission to make such disclosure. This information shall be treated as Confidential Information, but its disclosure pursuant to subsection (b) below is expressly permitted in accordance with the terms of the ISO New England Information Policy. Customers and applicants may satisfy the requirements above by providing the ISO with filings made to the Securities and Exchange Commission or other similar regulatory agencies that include substantially similar information to that required above, provided, however, that the customer or applicant must clearly indicate where the specific information is located in those filings. An applicant that fails to provide this information will be prohibited from participating in the New England Markets until the deficiency is rectified. If a customer fails to provide this information by end of business on April 30, then the ISO shall issue a notice of such failure to the customer on the next Business Day and, if the customer does not provide the information to the ISO within 5 Business Days after issuance of such notice, then the customer will be suspended as described in Section III.B.3 of the ISO New England Financial Assurance Policy until the deficiency is rectified.

(b) The ISO will review the information provided pursuant to subsection (a) above, and will also review whether the customer or applicant or any of the Principals of the customer or applicant are included on any relevant list maintained by the U.S. Office of Foreign Asset Control. If, after review of the information provided pursuant to subsection (a) above or any other information disclosed pursuant to this Section II, the ISO in its sole discretion requires additional information to make its analysis under this subsection (b), the ISO may require additional information from the customer or applicant. If, based on these reviews, the ISO determines that the commencement or continued participation of such customer or applicant in the New England Markets may present an unreasonable risk to those markets or its Market Participants, the Chief Financial Officer of the ISO shall promptly forward to the Participants Committee or its delegate, for its input, such concerns, together with such background materials deemed by the ISO to be necessary for the Participants Committee or its delegate to develop an informed opinion with respect to the identified concerns, including any measures that the ISO may recommend imposing as a condition to the commencement or continued participation in the markets by such customer or applicant (including suspension) or the ISO's recommendation to prohibit or terminate participation by the customer or applicant in the New England Markets. The ISO shall consider the input of the Participants Committee or its delegate before taking any action to address the identified concerns. If the ISO chooses to impose measures other than prohibition (in the case of an applicant) or termination (in the case of a customer) of participation in the New England Markets, then the ISO shall be required to make an informational filing with the Commission as soon as reasonably practicable after taking such action. If the ISO chooses to prohibit (in the case of an applicant) or terminate (in the case of a customer) participation in the New England Markets, then the ISO must file for Commission approval of such action, and the prohibition or termination shall become effective only upon final Commission ruling. No action by the ISO pursuant to this subsection (b) shall limit in any way the ISO's rights or authority under any other provisions of the ISO New England Financial Assurance Policy or the ISO New England Billing Policy.

2. Risk Management

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

(b) Each applicant prior to commencing activity in the FTR market shall submit to the ISO or its designee the written risk management policies, procedures, and controls, including, if requested by the ISO in its sole discretion, supporting documentation (which may include an organizational chart (or portion thereof) or equivalent information) that demonstrates the segregation of duties within such risk policies, procedures, and controls of the such customer or applicant, applicable to its participation in the FTR market relied upon by the Senior Officer of the applicant signing the certificate provided pursuant to Section II.A.2 (a). On an annual basis (by April 30 each year), each Designated FTR Participant with FTR transactions in any of the previous twelve months or in any currently open month that exceed 1,000 MW per month (on a net basis, as described in the FTR Financial Assurance Requirements provisions in Section VI) shall submit to the ISO or its designee a certificate in the form of Attachment 5 to the ISO New England Financial Assurance Policy stating that, since the customer's delivery of its risk management policies, procedures, and controls (and any supporting documentation, if applicable) or its last certificate pursuant to this Section II.A.2(b), the customer either: (i) has not made any changes to the previously submitted written risk management policies, procedures, and controls (and any supporting documentation, if applicable); or (ii) that changes have been made to the previously submitted written risk management policies, procedures, and controls (and any supporting documentation, if applicable) and that all such changes are clearly identified and attached to such certificate. If any such applicant fails to submit the relevant written policies, procedures, and controls, then the applicant will be prohibited from participating in the FTR market. If any such customer fails to provide a certificate in the form of Attachment 5 by end of business on April 30, then the ISO shall issue a notice of such failure to the customer, and if the customer does not provide the certificate to the ISO within two Business Days after issuance of such notice, then the customer will be suspended (as described in Section III.B.3.c of the ISO New England Financial Assurance Policy) from entering into any future transactions in the FTR system.

The ISO, at its sole discretion, may also require any applicant or customer to submit to the ISO or its designee the written risk management policies, procedures, and controls, including supporting documentation (which may include an organizational chart (or portion thereof) or equivalent information) that demonstrates the segregation of duties within such risk policies, procedures, and controls of the such customer or applicant, that are applicable to its participation in the New England Markets relied upon by the Senior Officer of the applicant or customer signing the certificate provided pursuant to Section II.A.2(a). The ISO may require such submissions based on identified risk factors that include, but are not limited to, the markets in which the customer is transacting or the applicant seeks to transact, the magnitude of the customer's transactions or the applicant's potential transactions, or the volume of the customer's open positions. Where the ISO notifies an applicant or customer that such a submission is required, the submission shall be due within 5 Business Days of the notice. If an applicant fails to submit the relevant written policies, procedures, and controls as required, then the applicant will be prohibited from participating in the New England Markets. If a customer fails to submit the relevant written policies, procedures, and controls, then the ISO shall issue a notice of such failure to the customer, and if the customer fails to submit the relevant written policies, procedures, and controls to the ISO or its designee within two Business Days after issuance of such notice, then the customer will be suspended (as described in Section III.B of the ISO New England Financial Assurance Policy).

The applicant's or customer's written policies, procedures, ~~and~~ controls, and any supporting documentation, received by the ISO or its designee pursuant to this subsection (b) shall be treated as Confidential Information.

(c) Where an applicant or customer submits risk management policies, procedures, and controls, or supporting documentation to the ISO or its designee pursuant to any provision of subsection (b) above, the ISO or its designee shall assess that those policies, procedures, and controls conform to prudent risk management practices, which include, but are not limited to: (i) addressing market, credit, and operational risk; (ii) segregating roles, responsibilities, and functions in the organization; (iii) establishing delegations of authority that specify which transactions traders are authorized to enter into; (iv) ensuring that traders have sufficient training in systems and the markets in which they transact; (v) placing risk limits to control exposure; (vi) requiring reports to ensure that risks are adequately communicated throughout the organization; (vii) establishing processes for independent confirmation of executed transactions; and (viii) establishing periodic valuation or mark-to-market of risk positions as appropriate.

Where, as a result of the assessment described above in this subsection (c), the ISO or its designee believes that the applicant's or customer's written policies, procedures, and controls do not conform to prudent risk management practices, then the ISO or its designee shall provide notice to the applicant or customer explaining the deficiencies. The applicant or customer shall revise its policies, procedures, and controls to address the deficiencies within 55 days after issuance of such notice. (If April 30 falls within that 55 day window, the ISO may choose not to require a separate submission on April 30 as described in subsection (b) above.) If an applicant's revised written policies, procedures, and controls do not adequately address the deficiencies identified in the notice, then the applicant will be prohibited from participating in the New England Markets. If a customer's revised written policies, procedures, and controls do not adequately address the deficiencies identified in the notice, then the customer will be suspended (as described in Section III.B of the ISO New England Financial Assurance Policy).

3. Communications

Each customer and applicant shall submit, on an annual basis (by April 30 each year), a certificate in the form of Attachment 3 to the ISO New England Financial Assurance Policy stating that the customer or applicant has either established or contracted to establish procedures to effectively communicate with and respond to the ISO with respect to matters relating to the ISO New England Financial Assurance Policy and the ISO New England Billing Policy. Such procedures must ensure, at a minimum, that at least one person with the ability and authority to address matters related to the ISO New England Financial Assurance Policy and the ISO New England Billing Policy on behalf of the customer or applicant, including the ability and authority to respond to requests for information and to arrange for additional financial assurance as necessary, is available from 9:00 a.m. to 5:00 p.m. Eastern Time on Business Days. Such procedures must also ensure that the ISO is kept informed about the current contact information (including phone numbers and e-mail addresses) for the person or people described above. The certificate must be signed on behalf of the customer or applicant by a Senior Officer of the customer or applicant and must be notarized. An applicant that fails to provide this certificate will be prohibited from participating in the New England Markets until the deficiency is rectified. If a customer fails to provide this certificate by end of business on April 30, then the ISO shall issue a notice of such failure to the customer on the next

Business Day and, if the customer does not provide the certificate to the ISO within 5 Business Days after issuance of such notice, then the customer will be suspended as described in Section III.B.3 of the ISO New England Financial Assurance Policy until the deficiency is rectified.

4. Capitalization

(a) To be deemed as meeting the capitalization requirements, a customer or applicant shall either:

(i) be Rated and have a Governing Rating that is an Investment Grade Rating of BBB-/Baa3 or higher;

(ii) maintain a minimum Tangible Net Worth of one million dollars; or

(iii) maintain a minimum of ten million dollars in total assets, provided that, to meet this requirement, a customer or applicant may supplement total assets of less than ten million dollars with additional financial assurance in an amount equal to the difference between ten million dollars and the customer's or applicant's total assets in one of the forms described in Section X (any additional financial assurance provided pursuant to this Section II.A.4(a) shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy).

(b) Any customer or applicant that fails to meet these capitalization requirements will be suspended (as described in Section III.B.3.c of the ISO New England Financial Assurance Policy) from entering into any future transactions of a duration greater than one month in the FTR system or any future transactions for a duration of one month or less except when FTRs for a month are being auctioned for the final time. Such a customer or applicant may enter into future transaction of a duration of one month or less in the FTR system in the case of FTRs for a month being auctioned for the final time. Any customer or applicant that fails to meet these capitalization requirements shall provide additional financial assurance in one of the forms described in Section X of the ISO New England Financial Assurance Policy equal to 25 percent of the customer's or applicant's FTR Financial Assurance Requirements. Any additional financial assurance provided pursuant to this Section II.A.4(b) shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy.

(c) For markets other than the FTR market:

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

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

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

5. Additional Eligibility Requirements

All customers and applicants shall at all times be:

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

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

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

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

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

The ISO, at its sole discretion, may require any applicant or customer to submit to the ISO documentation in support of the certification provided pursuant to this Section II.A.5. If at any time the ISO becomes aware that a customer no longer satisfies the requirements of this Section II.A.5, the customer shall be immediately suspended and the ISO shall initiate termination proceedings against the customer.

6. Prior Uncured Defaults

In addition to, and not in limitation of Section IV of the ISO New England Financial Assurance Policy, an applicant who has a previous uncured payment default must cure such payment default by payment to the ISO of all outstanding and unpaid obligations, as well as meet all requirements for participation in the New England Markets contained in the ISO New England Financial Assurance Policy. For purposes of this Section II.A.6 and the ISO's evaluation of information disclosed pursuant to Section II of the ISO New England Financial Assurance Policy, the ISO will evaluate relevant factors to determine if an entity seeking to participate in the New England Markets under a different name, affiliation, or organization, should be treated as the same customer or applicant that experienced the previous payment default. Such factors may include, but are not limited to, the interconnectedness of the business relationships, overlap in relevant personnel, similarity of business activities, overlap of customer base, and the business engaged in prior to the attempted re-entry. Notwithstanding the foregoing, an applicant shall not be required to cure a payment default that has lawfully been discharged pursuant to the U.S. Bankruptcy Code.

B. Proof of Financial Viability for Applicants

Each Applicant must, with its membership application and at its own expense, submit proof of financial viability, as described below, satisfying the ISO requirements to demonstrate the Applicant's ability to meet its obligations. Each Applicant that intends to establish a Market Credit Limit or a Transmission Credit Limit of greater than $0 under Section II.D or Section II.E below must submit to the ISO all current rating agency reports from Standard and Poor's ("S&P"), Moody's and/or Fitch (collectively, the "Rating Agencies"). Each Applicant, whether or not it intends to establish a Market

ATTACHMENT 5

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

Certifying Entity:	

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

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

   OR

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

____
(Signature)

Print Name:__________________________________

Title: ____

Date: ____

Subscribed and sworn before me_____________________________________, a notary public of the State of _______________________________, in and for the County of _________________________, this _______ day of _________________________, 20_______.

____

(Notary Public Signature)

My commission expires: _____/_____/_____

____

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

ATTACHMENT 6

MINIMUM CRITERIA FOR MARKET PARTICIPATION
INFORMATION DISCLOSURE FORM

Date: ____

Prepared by: ____

Customer/Applicant:[1] ____

I, __________________________, a duly authorized Senior Officer of ________________ ("Certifying Entity"), understanding that ISO New England Inc. ("ISO") is relying on this certification provided pursuant to Financial Assurance Policy Section II.A.1(a), hereby certify that I have full authority to bind Certifying Entity and further certify on behalf of Certifying Entity that the information contained herein is true, complete, and correct and is not misleading or incomplete for any reason, including by reason of omission:

1. List of all Principals.[2] Please discuss each Principal's relationship with the Certifying Entity and describe each Principal's previous experience related to participation in North American wholesale or retail energy markets or trading exchanges:

[1] Customer and Applicant are each defined in Section II.A of the ISO New England Financial Assurance Policy, Exhibit 1A to Section 1 of the ISO Transmission, Markets, and Services Tariff ("Tariff"). Capitalized terms used but not otherwise defined herein shall have the meaning given to them in the Tariff.

[2] Principal is (i) the sole proprietor of a sole proprietorship; (ii) a general partner of a partnership; (iii) a president, chief executive officer, chief operating officer or chief financial officer (or equivalent position) of an organization; (iv) a manager, managing member or a member vested with the management authority for a limited liability company or limited liability partnership; (v) any person or entity that has the power to exercise a controlling influence over an organization's activities that are subject to regulation by the Federal Energy Regulatory Commission ("FERC"), the Securities and Exchange Commission ("SEC"), the Commodity Futures Trading Commission ("CFTC"), any exchange monitored by the National Futures Association ("NFA"), or any state entity responsible for regulating activity in energy markets; or (vi) any person or entity that: (a) is the direct owner of 10% or more of any class of an organization's equity securities; or (b) has directly contributed 10% or more of an organization's capital.

2. List all material litigation (criminal or civil) against Certifying Entity or any of the Certifying Entity's Principals, Personnel,[3] or Predecessors,[4] arising out of participation in any wholesale or retail energy market (domestic or international) or trading exchanges in the past ten (10) years:
(Enter N/A if not applicable)

3. List all sanctions issued against or imposed upon Certifying Entity, Certifying Entity's Principals, Personnel, or Predecessors, by the FERC, the SEC, the CFTC, any exchange monitored by the NFA, or any entity responsible for regulating activity in any wholesale or retail energy market (domestic or international) or trading exchanges where such sanctions were either imposed in the past ten (10) years or, if imposed prior to that, are still in effect. List all known material ongoing investigations regarding Certifying Entity, Certifying Entity's Principals, Personnel, or Predecessors, imposed by the FERC, the SEC, the CFTC, any exchange monitored by the NFA, or any entity responsible for regulating activity in any wholesale or retail energy market (domestic or international) or trading exchanges:
(Enter N/A if not applicable)

4. Provide a summary of any bankruptcy, dissolution, merger, or acquisition of Certifying Entity in the past ten (10) years (include date, jurisdiction, and other relevant details):
(Enter N/A if not applicable)

5. List all wholesale or retail energy market-related operations in North America where Certifying Entity is currently participating, or, in the past five (5) years, has previously participated other than in the New England Markets (e.g., PJM - FTRs):
(Enter N/A if not applicable)

6. Describe if Certifying Entity or any of Certifying Entity's Principals, Personnel, or any Predecessor of the foregoing ever had its participation or membership in any independent system operator or regional transmission organization (domestic or international) terminated, its registration/membership application denied, or is subject to an existing uncured suspension from participating in the markets of any independent system operator or regional transmission organization (domestic or international), each in the past five (5) years.
(Enter N/A if not applicable)

[3] Personnel means any person, current or former, responsible for decision making regarding Certifying Entity's transaction of business in the New England Markets, including, without limitation, decisions regarding risk management and trading, or any person, current or former, with access to enter transactions into ISO systems. Disclosures regarding former Personnel shall only be required for when such Personnel was employed by Certifying Entity.

[4] Predecessor shall mean any person or entity whose liabilities, including liabilities arising under the Tariff, have or may have been retained or assumed by Certifying Entity, either contractually, by operation of law or considering all relevant factors, including the interconnectedness of the business relationships, overlap in relevant personnel, similarity of business activities, overlap of customer base.

If you are currently an active participant and this is your annual submission you do not have to complete Question 7 and can skip to the signature block below. If you are in the process of applying for membership with the ISO you are required to answer the additional questions listed below.

7. Describe how Certifying Entity plans to fund its operations, including persons or entities providing financing and such person(s)' or entity(ies)' relationship to the Certifying Entity. Include any relationships that may impact Certifying Entity's ability to (a) comply with the time frames to post financial assurance and/or pay invoices or other amounts owed to the ISO, each as required by the Tariff; or (b) provide a first priority perfected security interest in required financial assurance to the ISO:

Certifying Entity: ____________________

By: ____________________
(Signature)

Print Name: ____________________

Title: ____________________

Date: ____________________

** To satisfy the disclosure requirements above, a Certifying Entity may attach additional materials and may provide the ISO with filings made to the SEC or other similar regulatory agencies that include substantially similar information to that required above, provided that Certifying Entity clearly indicates where the specific information is located in those filings.

MINIMUM CRITERIA FOR MARKET PARTICIPATION

INFORMATION DISCLOSURE FORM

Date: ____

Prepared by: ____

Customer/Applicant:[1] ____

I, _________________________, a duly authorized Senior Officer of ______________ ("Certifying Entity"), understanding that ISO New England Inc. ("ISO") is relying on this certification provided pursuant to Financial Assurance Policy Section II.A.1(a), hereby certify that I have full authority to bind Certifying Entity and further certify on behalf of Certifying Entity that the information contained herein is true, complete, and correct and is not misleading or incomplete for any reason, including by reason of omission:

1. List of all Principals.[2] Please discuss each Principal's relationship with the Certifying Entity and describe each Principal's previous experience related to participation in North American wholesale or retail energy markets or trading exchanges:

2. List all material litigation (criminal or civil) ~~involving~~ against Certifying Entity or any of the Certifying Entity's Principals, Personnel ~~(current and/or former)~~,[3] or Predecessors,[4] ~~or an entity that a Principal of the Certifying Entity was a Principal of,~~ arising out of participation in any wholesale or retail energy market (domestic or international) or trading exchanges in the past ten (10) years:
(Enter N/A if not applicable)

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[1] Customer and Applicant are each defined in Section II.A of the ISO New England Financial Assurance Policy, Exhibit 1A to Section 1 of the ISO Transmission, Markets, and Services Tariff ("Tariff"). Capitalized terms used but not otherwise defined herein shall have the meaning given to them in the Tariff.

[2] Principal is (i) the sole proprietor of a sole proprietorship; (ii) a general partner of a partnership; (iii) a president, chief executive officer, chief operating officer or chief financial officer (or equivalent position) of an organization; (iv) a manager, managing member or a member vested with the management authority for a limited liability company or limited liability partnership; (v) any person or entity that has the power to exercise a controlling influence over an organization's activities that are subject to regulation by the Federal Energy Regulatory Commission ("FERC"), the Securities and Exchange Commission ("SEC"), the Commodity Futures Trading Commission ("CFTC"), any exchange monitored by the National Futures Association ("NFA"), or any state entity responsible for regulating activity in energy markets; or (vi) any person or entity that: (a) is the direct owner of 10% or more of any class of an organization's equity securities; or (b) has directly contributed 10% or more of an organization's capital.

[3] Personnel means any person, current or former, responsible for decision making regarding Certifying Entity's transaction of business in the New England Markets, including, without limitation, decisions regarding risk management and trading, or any person, current or former, with access to enter transactions into ISO systems. Disclosures regarding former Personnel shall only be required for when such Personnel was employed by Certifying Entity.

[4] Predecessor shall mean any person or entity whose liabilities, including liabilities arising under the Tariff, have or may have been retained or assumed by Certifying Entity, either contractually, by operation of law or considering all relevant factors, including the interconnectedness of the business relationships, overlap in relevant personnel, similarity of business activities, overlap of customer base.

3. List all sanctions ~~involving~~ issued against or imposed upon Certifying Entity, Certifying Entity's Principals, Personnel ~~(current and/or former)~~, or Predecessors, ~~or an entity that a principal of the Certifying Entity was a Principal of, imposed~~ by the FERC, the SEC, the CFTC, any exchange monitored by the NFA, or any ~~state~~ entity responsible for regulating activity in any wholesale or retail energy market (domestic or international) or trading exchanges where such sanctions were either imposed in the past ten (10) years or, if imposed prior to that, are still in effect. List all known material ongoing investigations ~~involving~~ regarding Certifying Entity, Certifying Entity's Principals, Personnel ~~(current and/or former)~~, or Predecessors, ~~or an entity that a principal of the Certifying Entity was a Principal of,~~ imposed by the FERC, the SEC, the CFTC, any exchange monitored by the NFA, or any ~~state~~ entity responsible for regulating activity in any wholesale or retail energy market (domestic or international) or trading exchanges:
(Enter N/A if not applicable)

4. Provide a summary of any bankruptcy, dissolution, merger, or acquisition of Certifying Entity in the past ten (10) years (include date, jurisdiction, and other relevant details):
(Enter N/A if not applicable)

5. List all wholesale or retail energy market-related operations in North America where Certifying Entity is currently participating, or, in the past five (5) years, has previously participated other than in the New England Markets (e.g., PJM - FTRs):
(Enter N/A if not applicable)

6. Describe if Certifying Entity or any of Certifying Entity's Principals, Personnel ~~(current and/or former)~~, or any Predecessor of the foregoing ever had its participation or membership in any independent system operator or regional transmission organization (domestic or international) terminated, its registration/membership application denied, or is subject to an existing uncured suspension from participating in the markets of any independent system operator or regional transmission organization (domestic or international), each ~~in the~~ in the past five (5) years. ~~If so, please explain:~~
(Enter N/A if not applicable)

If you are currently an active participant and this is your annual submission you do not have to complete Question 7 and can skip to the signature block below. If you are in the process of applying for membership with the ISO you are required to answer the additional questions listed below.

7. Describe how Certifying Entity plans to fund its operations, including persons or entities providing financing and such person(s)' or entity(ies)' relationship to the Certifying Entity. Include any relationships that may impact Certifying Entity's ~~(a)~~ ability to (a) comply with the time frames to post financial assurance and/or pay invoices or other amounts owed to the ISO, each as required by the Tariff; or (b) provide a first priority perfected security interest in required financial assurance to the ISO:

Certifying Entity: ______________________________________

By: ____
(Signature)

Print Name: ____

Title: ____

Date: ____

** To satisfy the disclosure requirements above, a Certifying Entity may attach additional materials and may provide the ISO with filings made to the SEC or other similar regulatory agencies that include substantially similar information to that required above, provided that Certifying Entity clearly indicates where the specific information is located in those filings.

FAQ is posted for informational purposes only and relates to FAP language currently under discussion through the stakeholder process

The FAQs listed below relate to the disclosures required by Attachment 6 to the ISO New England Financial Assurance Policy (the "FAP") and do not address all issues and requirements of Attachment 6. In case of any discrepancy between the answers to these FAQs and the FAP, the FAP governs.

1. **The Form is required to be signed and certified by a "duly authorized Senior Officer." What is a duly authorized Senior Officer?**

   Senior Officer as defined by the Tariff is "an officer of the subject entity with the title of vice president (or similar office) or higher, or another officer designated in writing to the ISO by that officer."

   The Senior Officer must have the authority to sign on behalf of the Certifying Entity.

   If the Senior Officer signing on behalf of Certifying Entity is not a vice president or higher and the Certifying Entity wishes to designate another officer, then a letter to the ISO confirming such authority must be provided.

2. **Questions 2, 3, and 6 require information about Predecessors. Could you provide an example of a Predecessor? Predecessor is defined in Footnote 4 of the Form.**

   A Predecessor is a person *or* an entity. One example may be if an entity filed for bankruptcy and ceased operations, and its principals had a previously inactive entity that began operating substantially the same business. The determination of Predecessor is fact specific based on the factors contained in the definition.

3. **Could you provide an example for Question 1?**

   Robert Brown worked for TransCanada as a natural gas trader trading in PJM markets for 5 years, then for Tennessee Gas Pipeline as a gas analyst for 4 years.

   Tim Smith worked as a CFO for NYMEX gas for 10 years and NSTAR as an energy market analyst for 8 years.

4. **For Question 1, is a person's resume required?**

   While you can provide a resume, this is not necessary or what the ISO is looking for. The relevant information can be more efficiently disclosed by listing each Principal and their relationship with the Certifying Entity and their previous experience related to participation in North American wholesale or retail energy (See FAQ Question 3 above).

FAQ is posted for informational purposes only and relates to FAP language currently under discussion through the stakeholder process

5. **Questions 1, 2, 3, and/or 5 require information about wholesale or retail energy markets and/or trading exchanges. Could you provide examples of wholesale and retail energy markets, and trading exchanges?**

   Energy Markets: such as oil, natural gas & LNG, NGLs, power, coal, freight, and environmental.

   Exchanges: such as Chicago Mercantile Exchange, Intercontinental Exchange, Nodal Exchange and New York Stock Exchange.

6. **Questions 2, 3, and 6 require information about Personnel. The definition for Personnel is in Footnote 3 and includes persons, current or former, responsible for decision making regarding Certifying Entity's transaction of business in the New England Markets, including, without limitation, decisions regarding risk management and trading, or any person, current or former, with access to enter transactions into ISO systems Could you list out some examples of ISO systems referred to in that definition?**

   Internal Transactions for submitting contracts

   eMarket for submitting bids and offers into the energy market

   NEXTT for submitting external transactions

   FTR for submitting FTR bids

   Forward Reserve Auction

   Metering Reading Submittal UI

   Forward Capacity Tracking System

   Forward Reserve Assignments

   Reconfiguration Auctions

7. **Questions 2, 3, and 6 require information about Personnel, do I need to disclose information about Personnel who are no longer with my company?**

   Maybe, The definition of Personnel, contained in Footnote 3, only requires disclosures regarding former Personnel if the triggering event was when such Personnel was employed by Certifying Entity and the person otherwise meets the definition of Personnel (i.e., person was responsible for decision making regarding Certifying Entity's transaction of business in the New England Markets, including, without limitation, decisions regarding risk management and trading, or any person, current or former, with access to enter transactions into ISO systems). For example, if an employee was involved in material litigation because of alleged market manipulation in wholesale energy markets while such person was employed by Certifying Entity, but has since left the company, such litigation must be disclosed.

FAQ is posted for informational purposes only and relates to FAP language currently under discussion through the stakeholder process

8. **For Question 3, do I need to disclose a matter that was referred to FERC but never resulted in a sanction?**

   No, if the referred matter did not result in a sanction or is not subject to an ongoing material investigation.

9. **What if we have confidential information (e.g., confidential ongoing investigations) that we are unable to disclose?**

   Pursuant to Section II.A.1(a) the FAP, you are not be required to disclose information required by Attachment 6 if such disclosure is prohibited by law; **provided, however, if the disclosure of any information required by Attachment 6 is prohibited by law, then customer or applicant shall use reasonable efforts to obtain permission to make such disclosure.**

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Sebastian Lombardi and Rosendo Garza, NEPOOL Counsel

DATE: October 29, 2020

RE: ISO-NE's Proposed Methodology to Recalculate the Dynamic De-List Bid Threshold

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At the November 5, 2020 Participants Committee teleconference meeting, you will be asked to vote on Tariff revisions that reflect a new method to calculate the Dynamic De-List Bid Threshold (DDBT) in the Forward Capacity Market (FCM), as proposed by the ISO (the ISO's DDBT Proposal). A copy of the ISO's proposed Tariff revisions are provided with this memorandum. (*See* Attachment A.)

As described further herein, the NEPOOL Markets Committee considered several stakeholder-sponsored motions to amend the ISO's DDBT Proposal. We have been advised that, since the Markets Committee's consideration, the proponents of these amendments (representatives from Calpine, NESCOE, and Dynegy (Vistra)) have worked together to produce a single, consolidated amendment for the Participants Committee's consideration. This new alternative proposal will be presented jointly at the November 5 meeting. Additional details on the Calpine/NESCOE/Dynegy (Vistra)-sponsored amendment are included with this memorandum as Attachment D.

I. BACKGROUND SUMMARY OF CURRENT DDBT

If a Lead Market Participant with an Existing Capacity Resource,[1] or a portion thereof, wishes to remove itself from an upcoming Forward Capacity Auction (FCA) for a one-year period, the Participant must submit a Static De-List Bid that reflects the lowest price in $/kW-month it is willing to accept and still supply capacity. The resource submits its de-list bid to the ISO's Internal Market Monitor (IMM) prior to the auction during the FCA qualification process. If the de-list bid is at or above the DDBT (which was last updated in 2018 when it was set at $4.30/kW-month), then the resource's Static De-List Bid will be reviewed by the IMM for the potential exercise of seller-side market power.[2] If the final Capacity Clearing Price is less than the amount specified in the IMM-reviewed bid, then the resource is de-listed for a year, i.e.,

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[1] Capitalized terms not defined herein have the meanings ascribed in the Second Restatement NEPOOL Agreement, Participants Agreement, or the ISO-NE Transmission, Markets and Services Tariff.

[2] As explained in past DDBT-related FERC filings, the DDBT is an administrative reference point for the IMM to screen de-list bids for market power. The IMM has concluded that, if the DDBT is set appropriately, de-list bids below the DDBT will be unable to successfully exercise market power, and the IMM will not review those bids for purposes of mitigation. To review the IMM's perspective on the role of the DDBT, please click here.

forging capacity payments and not receiving a Capacity Supply Obligation for the Capacity Commitment Period associated with the FCA.

II. THE ISO'S DDBT PROPOSAL

The ISO proposes a new methodology to calculate the DDBT. As an initial matter, the ISO proposes to recalculate the DDBT annually rather than every three years. Starting with FCA 16, the ISO would calculate a preliminary DDBT by averaging the preceding FCA's Capacity Clearing Price[3] and the estimated upcoming FCA's system-wide demand curve price. The ISO's proposed Tariff changes define the parameters and the method the ISO would use to construct the estimated system-wide demand curve for the upcoming FCA.

The ISO also proposes to limit the DDBT value each year with upper and lower bounds. The Net Cost of New Entry (CONE) value for the upcoming FCA would establish the upper bound value, and 75 percent of the preceding FCA's clearing price would establish the lower bound. If the finalized DDBT value were constrained by either the upper or lower bound values, then the ISO would post this information on the ISO's website. The ISO intends to publish the final DDBT value five business days prior to the retirement bid deadline for each FCA cycle (in early March).

Further details on the ISO's DDBT Proposal are included with this memorandum as Attachment B.[4]

III. STAKEHOLDER PROCESS TO DATE

On October 6, 2020, the NEPOOL Markets Committee took a series of votes on the ISO's DDBT Proposal and suggested amendments to it. There were four amendments offered, none of which were supported by the Markets Committee. The ISO's un-amended DDBT proposal also failed at the Markets Committee, with a 44.53% Vote in favor.[5] A copy of the Notice of Actions of the Markets Committee detailing these votes is included with this memorandum as Attachment C.

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[3] The ISO has explained that the preceding FCA Capacity Clearing Price utilized for the new DDBT methodology is the rest-of-pool clearing price.

[4] Subsequent to the October Markets Committee meeting, the ISO made non-substantive, clarifying revisions to Section III.13.1.2.3.1A(b). These changes are reflected in the Tariff revisions provided in Attachment A that the Participants Committee will be asked to vote on.

[5] The individual Sector votes at the Markets Committee were as follows: *Generation* – 0% in favor, 16.70% opposed, 0 abstentions; *Transmission* – 11.13% in favor, 5.57% opposed, 1 abstention; *Supplier* – 0% in favor, 16.70% opposed, 7 abstentions; *Alternative Resources* – 0% in favor, 16.50% opposed, 2 abstentions; *Publicly Owned Entity* – 16.70% in favor, 0% opposed, 0 abstentions; and *End User* – 16.70% in favor, 0% opposed, 0 abstentions.

Motions at the Markets Committee to Amend the ISO's DDBT Proposal

As indicated, the Markets Committee voted on four motions to amend the ISO's DDBT Proposal at its October 6 meeting.

i. Dynegy/Calpine Amendment #1: Margin Adder

Dynegy/Calpine's first amendment sought to include a "margin adder" to the ISO's DDBT Proposal through a two-step process. Under this amendment, the ISO would first calculate a preliminary DDBT in a similar manner as stated in the ISO's DDBT Proposal. Next, this amendment would require the ISO to calculate a margin adder to that preliminary DDBT by applying a formula and thereby arrive at the final DDBT. Dynegy/Calpine Amendment #1 failed at the Markets Committee with a 49.90% Vote in favor.[6]

ii. Dynegy/Calpine Amendment #2: Offer Cap

Dynegy/Calpine's second amendment, which was offered after its Amendment #1 failed, proposed to remove a resource's obligation to commit to a Static De-List Bid price by the existing October deadline and converting it to a cap price. Under this amendment, a resource could de-list during the auction at any price up to the approved offer cap price. Dynegy/Calpine Amendment #2 failed with a 49.90% Vote.[7]

The IMM indicated that he did not support the Dynegy/Calpine amendments.[8]

iii. NESCOE Amendment #1: Add to and Modify the ISO's DDBT Upper Bound

NECOE's first amendment sought to modify the maximum the DDBT could be set under the new methodology. It proposed Tariff changes to lower the DDBT's upper bound to 85 percent of Net CONE (thereby not setting the DDBT at Net CONE) and to add an upper bound set at 125 percent of the prior FCA clearing price. NESCOE Amendment #1 failed at the Markets Committee with a 33.40% Vote in favor.

[6] To review the Markets Committee Vote outcome for the Dynegy/Calpine amendments, please see Attachment C.

[7] Further details on the Dynegy/Calpine amendments can be found by clicking here.

[8] To review the IMM's memorandum, please click here.

iv. NESCOE Amendment #2: Limit the Amount of Change in the DDBT

When NESCOE's first amendment failed to pass, NESCOE moved a second amendment that sought to limit the maximum rate of change in the DDBT from one FCA to the next. NESCOE proposed to limit the DDBT's change to be the prior FCA's DDBT plus 30 percent of Net CONE.[9] NESCOE Amendment #2 failed with a 33.40% Vote.[10]

In a memorandum issued to the Markets Committee, the ISO articulated its concerns with the NESCOE amendments.[11]

*We remind members that, if the Markets Committee voted but failed to support the proposed amendments, NEPOOL will not raise procedural objections to those same amendments if advanced in litigation without the benefit of a Participants Committee vote.

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

> RESOLVED, that the Participants Committee support the revisions to Market Rule 1 to modify the Dynamic De-List Bid Threshold in the Forward Capacity Market, as proposed by ISO-NE and circulated to this Committee in advance of this meeting, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

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[9] Further details on the NESCOE amendments can be found by clicking here.

[10] To review the Markets Committee Vote outcome for the NESCOE amendments, please see Attachment C.

[11] To read the ISO's memorandum, please click here.

ISO-NE PUBLIC

Note: blue highlight shows the non-substantive revision, as approved by the MC Chair and Vice Chair, made after the October 6-8 MC meeting.

III.13.1.2.3. Qualification Process for Existing Generating Capacity Resources.

(a) For each Existing Generating Capacity Resource, no later than 15 Business Days before the Existing Capacity Retirement Deadline, the ISO will notify the resource's Lead Market Participant of the resource's summer Qualified Capacity and winter Qualified Capacity and the Load Zone in which the Existing Generating Capacity Resource is located.

(b) If the Lead Market Participant believes that the ISO has made a mathematical error in calculating the summer Qualified Capacity or winter Qualified Capacity for an Existing Generating Capacity Resource as described in Section III.13.1.2.2, then the Lead Market Participant must notify the ISO within five Business Days of receipt of the Qualified Capacity notification.

(c) The ISO shall notify the Lead Market Participant of the outcome of any such challenge no later than five Business Days before the Existing Capacity Retirement Deadline. If an Existing Generating Capacity Resource does not submit a Static De-List Bid, an Export Bid, an Administrative Export De-List Bid, a Permanent De-List Bid, or a Retirement De-List Bid in the Forward Capacity Auction qualification process, then the resource shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c).

III.13.1.2.3.1. Existing Capacity Retirement Package and Existing Capacity Qualification Package.

A resource that previously has been deactivated pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) and seeks to reactivate and participate in the Forward Capacity Market as an Existing Generating Capacity Resource must submit a reactivation plan no later than 10 Business Days before the Existing Capacity Retirement Deadline, as described in Section III.13.1.1.1.6(b). All Permanent De-List Bids and Retirement De-List Bids in the Forward Capacity Auction must be detailed in an Existing Capacity Retirement Package submitted to the ISO no later than the Existing Capacity Retirement Deadline. All Static De-List Bids, Export Bids and Administrative Export De-List Bids in the Forward Capacity Auction must be detailed in an Existing Capacity

Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline. Permanent De-List Bids and Retirement De-List Bids may not be modified or withdrawn after the Existing Capacity Retirement Deadline, except as provided for in Section III.13.1.2.4.1. All Static De-List Bids, Export Bids, and Administrative Export De-List Bids submitted in the qualification process may not be modified or withdrawn after the Existing Capacity Qualification Deadline, except as provided for in Section III.13.1.2.3.1.1. An Existing Generating Capacity Resource may not submit a Static De-List Bid, Export Bid, Administrative Export De-List Bid, Permanent De-List Bid, or Retirement De-List Bid for an amount of capacity greater than its summer Qualified Capacity, unless the submittal is for the entire resource. Where a resource elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.1.1.2.7 to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, the capacity associated with any resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. For a single resource, a Lead Market Participant may combine a Static De-List Bid, an Export Bid, and an Administrative Export De-List Bid; neither a Permanent De-List Bid nor a Retirement De-List Bid may be combined with any other type of de-list or export bid.

Static De-List Bids and Export Bids may elect to be rationed (as described in Section III.13.2.6, however, an Export Bid is always subject to potential rationing where the associated external interface binds). Where a Lead Market Participant submits any combination of Static De-List Bid and Export Bid for a single resource, each of those bids must have the same rationing election. Where a Lead Market Participant submits any combination of Static De-List Bid, Export Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

III.13.1.2.3.1.A Dynamic De-List Bid Threshold.

For the fifteenth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2024), ~~T~~the Dynamic De-List Bid Threshold ~~for a Forward Capacity Auction~~ is $4.30/kW-month. For each Forward Capacity Auction thereafter, the Dynamic De-List Bid Threshold shall be calculated as described below in this Section III.13.1.2.3.1.A, and shall be published to the ISO's website no later than 5 Business Days before the Existing Capacity Retirement Deadline.

(a) Subject to the limitations described in subsection (b) below, the Dynamic De-List Bid Threshold shall be calculated as the average of: (i) the Capacity Clearing Price for the Rest-of-Pool Capacity Zone from the immediately preceding Forward Capacity Auction (provided, however, that if there is a second run of the primary auction-clearing process pursuant to Section III.13.2.5.2.1(d), the resulting Rest-of-Pool Capacity Zone clearing price from that run shall be used instead); and (ii) the price at which the total amount of capacity clearing in the immediately preceding Forward Capacity Auction intersects the estimated System-Wide Capacity Demand Curve for the upcoming Forward Capacity Auction. For this purpose, the estimated System-Wide Capacity Demand Curve shall be constructed, in the same manner as described in Section III.13.2.2.1, using the system-wide Marginal Reliability Impact values from the immediately preceding Forward Capacity Auction, the most recent estimate of the Installed Capacity Requirement (net of HQICCs) for the upcoming Forward Capacity Auction, and the Net CONE and Forward Capacity Auction Starting Price for the upcoming Forward Capacity Auction.

(b) The Dynamic De-List Bid Threshold shall not be higher than the Net CONE value for the upcoming Forward Capacity Auction.~~, and~~ The Dynamic De-List Bid Threshold shall not be lower than 75 percent of the clearing price applicable pursuant to (a)(i) of this Section III.13.1.2.3.1.A, ~~(~~except as needed to ensure that it is not higher than the Net CONE value for the upcoming Forward Capacity Auction~~ where the Net CONE value for the upcoming Forward Capacity Auction is lower than 75 percent of the clearing price applicable pursuant to (a)(i) of this Section III.13.1.2.3.1.A)~~. If the Dynamic De-List Bid Threshold is constrained by either of the limitations described in this subsection (b), the ISO shall so indicate in its publication of the Dynamic De-List Bid Threshold to the ISO's website.~~The Dynamic De-List Bid Threshold shall be recalculated for the Capacity Commitment Period beginning on June 1, 2025 and no less often than once every three years thereafter. When the Dynamic De-List Bid Threshold is recalculated, the Internal Market Monitor will review the results of the recalculation with stakeholders.~~

III.13.1.2.3.1.1. Static De-List Bids.

A Lead Market Participant with an Existing Capacity Resource, or a portion thereof, seeking to specify a price below which it would not accept a Capacity Supply Obligation for that resource, or a portion thereof, at prices at or above the Dynamic De-List Bid Threshold during a single Capacity Commitment Period may submit a Static De-List Bid in the associated Forward Capacity Auction qualification process. A Static De-List Bid may not result in a resource's Capacity Supply Obligation being less than its Rationing Minimum Limit except where the resource submits de-list and export bids totaling the resource's full summer Qualified Capacity. Each Static De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification memo

To: NEPOOL Markets Committee

From: Matthew Brewster

Date: September 30, 2020

Subject: Dynamic De-List Bid Threshold Recalibration (WMPP ID: 143)

The ISO is requesting a vote on revisions to Section III.13.1.2.3.1.A of the Tariff to update the calculation of the Dynamic De-List Bid Threshold (DDBT). This proposal will establish a process to recalculate the DDBT annually, starting with the sixteenth Forward Capacity Auction (FCA), using a transparent methodology and publicly available data.

The new annual recalibration methodology is an improvement over the current process, by which the ISO manually estimates the DDBT value every three years. The new annual recalibration approach will keep the DDBT better aligned with current market conditions and forecast changes in demand for the next FCA. The new approach is designed to be robust to a broad range of possible market conditions and to reasonably balance the functional design objectives for the DDBT. Retrospective analyses indicate that the new annual recalibration will generally improve the accuracy of the DDBT in estimating the competitive auction clearing price and, thus, will support its intended function as a screen for potential supply-side market power. Accordingly, the proposed DDBT calculation method will support the efficient administration of the annual FCA process going forward.

The proposal for the committee's consideration at its October 6-8, 2020 meeting has been presented previously to the Markets Committee at the meeting dates outlined below:

- July 14-15, 2020; agenda item 5C: https://www.iso-ne.com/event-details?eventId=140277
- August 11-13, 2020; agenda item 4C: https://www.iso-ne.com/event-details?eventId=140275
- September 8-10, 2020; agenda item 6B: https://www.iso-ne.com/event-details?eventId=142578

4851-3331-3739, v. 1

memo

To: Participants Committee

From: Erin Wasik-Gutierrez, Secretary, Markets Committee

Date: October 14, 2020

Subject: Actions of the Markets Committee

This memo is notification to the Participants Committee of the following actions taken by the Markets Committee (MC) at its October 6-8, 2020 meeting. All sectors had a quorum.

1. **(Agenda Item 2) NEPOOL Generation Information System (GIS) Referral Request**

   ACTION: REFERRED

   The request was referred to the NEPOOL GIS Operating Rules Working Group by the Markets Committee to discuss and determine potential changes to the to the GIS Operating Rules and/or the GIS relating to the addition of "Clean Existing Generation" to the Massachusetts Clean Energy Standard.

2. **(Agenda Item 4) Forward Reserve Market Sunset**

   ACTION: RECOMMEND SUPPORT

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

   > RESOLVED, that the Markets Committee recommends that the Participants Committee support the revisions to section III.9.1 of Market Rule 1 reflecting the sunset of the Forward Reserve Market (including the language contingent on the FERC's acceptance of key components of the ISO's Energy Security Improvements proposal), as proposed by ISO New England and as circulated for this meeting, with those further changes recommended by this Committee and such further non-substantive changes as the Chair and Vice-Chair may approve.

   The motion was then voted and passed based on a voice vote. 1 abstention from the Generation Sector, 1 abstention from the Transmission Sector, 1 opposed and 5 abstentions from the Supplier Sector, , 21 opposed from the Publicly Owned Entity Sector, 4 abstentions from the AR Sector, and 1 abstention from the End User were recorded.

3. **(Agenda Item 5A) Dynamic De-list Bid Threshold (DDBT)**

   ACTION: MOTION FAILED

ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841
413-540-4518
EWasikGutierrez@iso-ne.com

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

> RESOLVED, that the Markets Committee recommends that the Participants Committee support the revisions to sections III.13.1.2.3.1(A) and III.13.2.3.2 (a)(v) of Market Rule 1 for recalculating the Dynamic De-List Bid Threshold using updated data for FCA 16, as proposed by ISO New England and as circulated for this meeting, with those further changes recommended by this Committee and such further non-substantive changes as the Chair and Vice-Chair may approve.

(Vote 1 – Failed (*Calpine & Dynegy Amendment #1 (Margin Adder*)**)**

Before the main motion could be voted, it was moved and seconded by the Markets Committee to amend the main motion:

> RESOLVED, that the main motion be amended to reflect the changes to sections III.13.1.2.3.1(A) of Market Rule 1 as contained in the materials provided by Calpine and Dynegy to modify the ISO's proposed calculation of the DDBT to include a margin adder, as circulated for this meeting, with those further changes recommended by this Committee and such further non-substantive changes as the Chair and Vice-Chair may approve.

The motion to amend the main motion was then voted. The motion failed to pass with a vote of 49.90% in favor. The individual Sector votes were Generation (16.70% in favor, 0.00% opposed, 0 abstentions), Transmission (0.00% in favor, 16.70% opposed, 0 abstentions), Supplier (16.70% in favor, 0.00% opposed, 7 abstentions), Publicly Owned Entity (0.00% in favor, 16.70% opposed, 0 abstentions), Alternative Resources (16.50% in favor, 0.00% opposed, 1 abstention), and End User (0.00% in favor, 16.70% opposed, 1 abstention).

(Vote 2 – Failed (*Calpine & Dynegy Amendment #2 (Offer Cap*)**)**

Before the main motion could be voted, it was moved and seconded by the Markets Committee to amend the main motion:

> RESOLVED, that the main motion be amended to reflect the changes to section III.13.1.2.3.1.1 of Market Rule 1 as contained in the materials provided by Calpine and Dynegy to modify the Static De-List Bid Finalization Window to become an offer cap, as circulated for this meeting, with those further changes recommended by this Committee and such further non-substantive changes as the Chair and Vice-Chair may approve.

The motion to amend the main motion was then voted. The motion failed to pass with a vote of 49.90% in favor. The individual Sector votes were Generation (16.70% in favor, 0.00% opposed, 0 abstentions), Transmission (0.00% in favor, 16.70% opposed, 0 abstentions), Supplier (16.70% in favor, 0.00% opposed, 7 abstentions), Publicly Owned Entity (0.00% in favor, 16.70% opposed, 0 abstentions), Alternative Resources (16.50% in favor, 0.00% opposed, 1 abstention), and End User (0.00% in favor, 16.70% opposed, 1 abstention).

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(Vote 3 – Failed (NESCOE Amendment #1 *(Adding an Upper Bound*))

Before the main motion could be voted, it was moved and seconded by the Markets Committee to amend the main motion:

> RESOLVED, that the main motion be amended to reflect the changes to section III.13.1.2.3.1(A) of Market Rule 1 as contained in the materials provided by NESCOE adding an upper bound to the DDBT, as circulated for this meeting, with those further changes recommended by this Committee and such further non-substantive changes as the Chair and Vice-Chair may approve.

The motion to amend the main motion was then voted. The motion failed to pass with a vote of 33.40% in favor. The individual Sector votes were Generation (0.00% in favor, 16.70% opposed, 1 abstention), Transmission (16.70% in favor, 0.00% opposed, 0 abstentions), Supplier (0.00% in favor, 16.70% opposed, 7 abstentions), Publicly Owned Entity (0.00% in favor, 16.70% not in favor, 49 abstentions)[1], Alternative Resources (0.00% in favor, 16.50% opposed, 1 abstention), and End User (16.70% in favor, 0.00% opposed, 1 abstention).

(Vote 4 – Failed (NESCOE Amendment #2 *(Limiting the Maximum Rate of Change*))

Before the main motion could be voted, it was moved and seconded by the Markets Committee to amend the main motion:

> RESOLVED, that the main motion be amended to reflect the changes to section III.13.1.2.3.1(A) of Market Rule 1 as contained in the materials provided by NESCOE to limit the DDBT Maximum Rate of Change, as circulated for this meeting, with those further changes recommended by this Committee and such further non-substantive changes as the Chair and Vice-Chair may approve.

The motion to amend the main motion was then voted. The motion failed to pass with a vote of 33.40% in favor. The individual Sector votes were Generation (0.00% in favor, 16.70% opposed, 1 abstention), Transmission (16.70% in favor, 0.00% opposed, 0 abstentions), Supplier (0.00% in favor, 16.70% opposed, 7 abstentions), Publicly Owned Entity (0.00% in favor, 16.70% not in favor, 49 abstentions), Alternative Resources (0.00% in favor, 16.50% opposed, 1 abstention), and End User (16.70% in favor, 0.00% opposed, 1 abstention).

(Vote 5 – Failed (Main Motion))

The ISO proceeded to ask the Markets Committee to provide a vote on the ISO's proposed revisions to sections III.13.1.2.3.1(A) and III.13.2.3.2 (a)(v) of Market Rule 1 for recalculating the Dynamic De-List Bid Threshold using updated data for FCA 16.

[1] For this vote, with a Sector Quorum and all Sector members abstaining, no portion of the Adjusted Sector Voting Share was (i) reallocated to the other Sectors or (ii) included in either the totals in favor or opposed to the motion.

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The motion failed to pass with a vote of 44.53% in favor. The individual Sector votes were Generation (0.00% in favor, 16.70% opposed, 0 abstentions), Transmission (11.13% in favor, 5.57% opposed, 1 abstention), Supplier (0.00% in favor, 16.70% opposed, 7 abstentions), Publicly Owned Entity (16.70% in favor, 0.00% opposed, 0 abstentions), Alternative Resources (0.00% in favor, 16.50% opposed, 2 abstentions), and End User (16.70% in favor, 0.00% opposed, 0 abstentions).

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Dynamic Delist Bid Threshold (DDBT) Amendment

Calpine/NESCOE/Dynegy (Vistra) proposed change to how the DDBT is calculated

November NEPOOL Participants Committee

Overall Design - NESCOE

- NESCOE remains concerned that the ISO-NE proposal does not balance design objectives #1 (adequate review) and #2 (administration) and can result in the DDBT being set too high when:
  - Capacity prices are expected to increase
  - DDBT is set at or near Net CONE
- Risk of the DDBT being set too high (especially as it approaches Net CONE) creates the possibility that some bids that should be reviewed for the exercise of market power may not be reviewed
- This could have consumer cost implications

Overall Design – Calpine/Dynegy

- Calpine and Dynegy are concerned that ISO-NE's proposal fails to balance design objectives #1 (adequate review) and #2 (interference with competitive price formation) – particularly when expected prices are low:
  - ISO's design would effectively eliminate the original purpose and usefulness of the DDBT – irrespective of the expected clear, how flat the supply curve is, or whether any potential to exercise market power exists.
  - This interferes with competitive price formation, adds significant administrative burden and risks on existing suppliers, and adds an unnecessary barrier to market exit.
- The amendment allows a modest margin adder to ISO's proposal at low prices (when supply curves are typically flat), with the adder diminishing as expected prices increase. This would preserve at least some of the benefit of the DDBT.

Previous Amendments

- NESCOE presented two amendments at the October NEPOOL MC
  1. Lower the upper bound from Net CONE to 85% of Net CONE and add an upper bound set at 125% of the prior auction clearing price and,
  2. Limit the maximum rate of change in the DDBT from auction to auction based upon 30% of Net CONE
- Calpine/Dynegy presented two amendments at the MC
  1. Set the DDBT at ISO-NE's estimated clearing price plus a scaled margin that starts ~75 cents above ISO's estimated price at a $2 clear, declining to $0 at Net CONE
  2. As an alternative: Convert static finalization from a fixed bid to a cap price
- All the amendments failed to receive the required 60% support

Revised Joint Amendment

- Lower the ISO-NE DDBT upper bound to 75% of Net CONE
  - Modifies NESCOE's first amendment from the MC that set an 85% of Net CONE upper bound and eliminates 125% of prior auction clearing price upper bound
  - NESCOE's second amendment from the MC is eliminated
- Set the DDBT at ISO-NE's estimated clearing price plus a margin adder calculated using 75% of Net CONE
  - Modifies Calpine/Dynegy's first amendment from the MC to use NESCOE's proposed DDBT upper bound rather than Net CONE
  - If this passes Calpine/Dynegy will not move forward with their alternative proposal (NESCOE does not support this alternative)

Revised DDBT as a Formula

$$Estimated\ Clearing\ Price\ Lower\ Bound_t = Clearing\ Price_{t-1} \times 75\%$$

$$Estimated\ Clearing\ Price_t = MAX\left\{\frac{(\ Price_t + Clearing\ Price_{t-1}\ )}{2}, Estimated\ Clearing\ Price\ Lower\ Bound_t\right\}$$

$$DDBT\ Upper\ Bound_t = Net\ CONE_t \times 75\%$$

$$Prelim\ DDBT_t = MIN\ \{Estimated\ Clearing\ Price_t, DDBT\ Upper\ Bound_t\}$$

$$Margin\ Adder_t = \frac{(DDBT\ Upper\ Bound_t - \ Prelim\ DDBT_t)}{DDBT\ Upper\ Bound_t} \times \$1/kWmo$$

$$DDBT_t = Prelim\ DDBT_t + Margin\ Adder_t$$

Prior Period DDBT Comparison

FCA	ISO DDBT	75% of Net CONE	Proposed Margin	Proposed DDBT	Difference
9	$11.08	$ 8.31	$ 0.00	$8.31	**-$2.77**
10	$9.90	$ 8.11	$ 0.00	$8.11	**-$1.79**
11	$6.74	$ 8.73	$ 0.23	$6.97	**$0.23**
12	$3.98	$ 6.03	$ 0.34	$4.32	**$0.34**
13	$4.27	$ 6.12	$ 0.30	$4.57	**$0.30**
14	$2.85	$ 6.14	$ 0.54	$3.39	**$0.54**

Tariff Language, III.13.1.2.3.1A

III.13.1.2.3.1.A Dynamic De-List Bid Threshold.

For the fifteenth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2024), the Dynamic De-List Bid Threshold is $4.30/kW-month. For each Forward Capacity Auction thereafter, the Dynamic De-List Bid Threshold shall be calculated as described below in this Section III.13.1.2.3.1.A, and shall be published to the ISO's website no later than 5 Business Days before the Existing Capacity Retirement Deadline. This publication shall include the preliminary value calculated pursuant to subsection (a) below, whether the preliminary value was constrained by either of the limitations described in subsection (b) below, the margin value as calculated pursuant to subsection (c) below, and the final value as calculated pursuant to subsection (d) below.

Tariff Language, III.13.1.2.3.1A (a)

(a) Subject to the limitations described in subsection (b) below, the preliminary value of the Dynamic De-List Bid Threshold shall be calculated as the average of: (i) the Capacity Clearing Price for the Rest-of-Pool Capacity Zone from the immediately preceding Forward Capacity Auction (provided, however, that if there is a second run of the primary auction-clearing process pursuant to Section III.13.2.5.2.1(d), the resulting Rest-of-Pool Capacity Zone clearing price from that run shall be used instead); and (ii) the price at which the total amount of capacity clearing in the immediately preceding Forward Capacity Auction intersects the estimated System-Wide Capacity Demand Curve for the upcoming Forward Capacity Auction. For this purpose, the estimated System-Wide Capacity Demand Curve shall be constructed, in the same manner as described in Section III.13.2.2.1, using the system-wide Marginal Reliability Impact values from the immediately preceding Forward Capacity Auction, the most recent estimate of the Installed Capacity Requirement (net of HQICCs) for the upcoming Forward Capacity Auction, and the Net CONE and Forward Capacity Auction Starting Price for the upcoming Forward Capacity Auction.

Tariff Language, III.13.1.2.3.1A (b)

(b) The preliminary value of the Dynamic De-List Bid Threshold shall not be higher than 75 percent of the Net CONE value for the upcoming Forward Capacity Auction. The preliminary value of the Dynamic De-List Bid Threshold shall not be lower than 75 percent of the clearing price applicable pursuant to (a)(i) of this Section III.13.1.2.3.1.A, except as needed to ensure that it is not higher than 75 percent of the Net CONE value for the upcoming Forward Capacity Auction. ~~If the Dynamic De-List Bid Threshold is constrained by either of the limitations described in this subsection (b), the ISO shall so indicate in its publication of the Dynamic De-List Bid Threshold to the ISO's website.~~

Tariff Language, III.13.1.2.3.1A (c) and (d)

(c) A margin value shall be calculated using the following formula:

$$Margin = \$1/kW\text{-}month \times \left[\frac{\left(75\% \times Net\ CONE_{upcoming\ FCA}\right) - DDBT_{preliminary}}{\left(75\% \times Net\ CONE_{upcoming\ FCA}\right)}\right]$$

(d) The final value of the Dynamic De-List Bid Threshold for the upcoming Forward Capacity Auction will be equal to the preliminary value of the Dynamic De-List Bid Threshold calculated pursuant to Sections III.13.1.2.3.1.A(a) and III.13.1.2.3.1.A(b) plus the margin value calculated pursuant to Section III.13.1.2.3.1.A(c).

Questions

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Acronyms

- FCA – Forward Capacity Auction
- DDBT – Dynamic De-list Bid Threshold
- CONE – Cost of New Entry
- MC – Markets Committee

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

The following activity, as more fully described in the attached litigation report, has occurred since the report dated September 29, 2020 ("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	NECEC/Avangrid Complaint Against NextEra/Seabrook (EL21-6)	Oct 13	NECEC and Avangrid file complaint against NextEra
			Oct 16-Nov 2	Dominion, Eversource, Calpine, Exelon, HQ US, MA AG, MMWEC National Grid, NESCOE, NRG, Public Citizen intervene
			Nov 2	National Grid files comments;
*	3	NextEra Energy Seabrook Declaratory Order Petition re: NECEC Elective Upgrade Costs Dispute (EL21-3)	Oct 5	NextEra Energy Seabrook seeks declaratory order related to costs and requirements associated with the New England Clean Energy Connect project Elective Upgrade; comment date Nov 4, 2020
			Oct 13-Nov 2	Avangrid, Dominion, Eversource, Calpine, Exelon, HQ US, National Grid, NESCOE, NRG, Public Citizen intervene
			Nov 4	Eversource, MMWEC file comments
	5	Exelon PP-10 Complaint (EL20-52)	Oct 19	FERC issues notice of denial of rehearing by operation of law
	6	206 Investigation Into ISO-NE Implementation of Order 1000 Exemptions for Immediate Need Reliability Projects (EL19-90)	Oct 28	LSP Power petitions DC Circuit Court of Appeals for review of the FERC's *Order Terminating Proceeding* and *Order 1000 Exemptions Allegheny Order* (*see* Section XV)

II. Rate, ICR, FCA, Cost Recovery Filings

*	9	2021 NESCOE Budget (ER21-113)	Oct 15	ISO-NE files budget for funding NESCOE's 2020 operations; comment date Nov 5
			Oct 15-25	NEPOOL, Exelon, National Grid, NESCOE intervene
			Oct 29	NEPOOL files comments supporting NESCOE 2020 Budget
*	9	2021 ISO-NE Administrative Costs and Capital Budgets (ER21-106)	Oct 15	ISO-NE files its 2021 administrative costs and capital budgets; comment date Nov 5
			Oct 16-27	NEPOOL, MA AG, National Grid, NESCOE intervene
			Oct 28	NEPOOL files comments supporting ISO-NE 2021 Budgets
	10	Mystic 8/9 Cost of Service Agreement (ER18-1639)	Oct 6	***Sep 2020 Compliance Filing***: CT Parties, ENECOS protest Mystic's Sep 15 compliance filing
		ROE Paper Hearing	Oct 7	FERC Staff issues revised ROE initial brief
			Oct 28	CT Parties, EMCOS, MA AG, and FERC Trial Staff file responses to initial briefs addressing ROE methodology

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

	11	Gross Load Forecast Reconstitution Revisions (ER20-2869)	Sep 30 Oct 2 Oct 30	NEPOOL submits supplemental comments EDF/NRDC/ Sustainable FERC Project/UCS/CLF/Acadia submit joint comments supporting revisions FERC accepts revisions, eff. Nov 10, 2020
	11	ESI Alternatives (ER20-1567)	Oct 30	FERC rejects as unjust and unreasonable both the ISO-NE and NEPOOL ESI proposals
	12	Waiver Request Dismissed as Moot: Vineyard Wind FCA13 Participation (ER19-570)	Oct 16	FERC dismisses as moot long-pending request for waiver

V. OATT Amendments / TOAs / Coordination Agreements

	17	CIP IROL Cost Recovery Rules (ER20-739)	Oct 14	Cogentrix and Vistra submit amended petition to the DC Circuit Court of Appeals for review of the FERC's *CIP IROL Orders* (*see* Section XV)

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Changes

	17	Schedule 20A-VP: Renaming / Clean-Up (ER20-2783)	Oct 29	FERC accepts changes, eff. Nov 1, 2020

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

*	19	Capital Projects Report - 2020 Q3 (ER20-108)	Oct 15 Oct 23-27 Oct 28	ISO-NE files 2020 Q3 Report; comment date Nov 5 NEPOOL, National Grid intervene NEPOOL files comments supporting Q3 Report
*	19	Capital Projects Report - 2020 Q2 (ER20-2640)	Oct 2	FERC accepts 2020 Q2 Report
*	19	LFTR Implementation: 48th Quarterly Status Report (ER07-476)	Oct 15	ISO-NE files its 48th quarterly report
*	19	Reserve Market Compliance (29th) Semi-Annual Report (ER06-613)	Oct 1	ISO-NE submits 29th semi-annual report

IX. Membership Filings

*	20	November 2020 Membership Filing (ER21-260)	Oct 30	***New Member***: Nautilus Solar Energy Supply, LLC (AR Sector, RG Sub-Sector, Large RG Group Seat); comment date Nov 20
*	20	October 2020 Membership Filing (ER20-3031)	Sep 30	***New Member***: David Energy Supply, LLC (Supplier Sector)
	20	September 2020 Membership Filing (ER20-2772)	Oct 13	FERC accepts (i) the memberships of: Acadia Renewable Energy, Sky View Ventures, and SYSO LLC; and (ii) the name change of ENGIE Power & Gas LLC (f/k/a Plymouth Rock Energy, LLC)
*	20	Suspension Notice – Curio Analytics (not docketed)	Oct 2	ISO-NE files notice of suspension of Curio Analytics, Inc. (an FTR-Only Participant) from the New England Markets

*	20	Suspension Notice – NS Power Energy Marketing, Inc. (not docketed)	Oct 20	ISO-NE files notice of suspension of NS Power Energy Marketing from the New England Markets
*	20	Suspension Notice – Manchester Methane, LLC (not docketed)	Oct 19	ISO-NE files notice of suspension of Manchester Methane, LLC from the New England Markets

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

	21	Revised Reliability Standards: FAC-002-3; IRO-010-3; MOD-031-3; MOD-033-2; NUC-001-4; PRC-006-4; TOP-003-4 (RD20-4)	Oct 30	FERC accepts Revised Standards, eff. Apr 1, 2021
*	23	Amended and Restated NERC Bylaws (RR21-1)	Oct 14	NERC petitions FERC for approval of its Amended and Restated Bylaws; comment date Nov 4, 2020
	24	2021 NERC/NPCC Business Plans and Budgets (RR20-6)	Nov 2	FERC accepts 2021 NERC and NPCC budgets

XI. Misc. - of Regional Interest

*	24	203 Application: CPV Towantic (EC21-16)	Oct 29	CPV Towantic, among others, requests authorization for a transaction whereby CPV Group LP will indirectly acquire all of the indirect voting securities owned by GIP II CPV; comment date Nov 19, 2020
*	25	VTransco Rate Schedule 2 Cancellation (ER21-256)	Oct 29	VTrasco files notice of cancellation of Rate Schedule 2 (Vermont Yankee Transmission Agreement); comment date Nov 19, 2020
*	25	D&E Agreement: NSTAR/Ocean State Power (ER21-192)	Oct 23	CL&P files D&E Agreement; comment date Nov 13, 2020
	25	NECEC TSAs: NECEC Transmission Notice of Succession and CMP Notice of Cancellation (ER21-12 et al.)	Oct 2	NECEC Transmission files notices of succession to, and CMP files notice of cancellation of, TSAs with NSTAR, National Grid, Fitchburg and HQ US that are being transferred from CMP to NECEC Transmission
	25	D&E Agreement: CL&P/UConn (ER20-2927)	Oct 26	FERC accepts D&E Agreement, eff. Sep 21, 2020
	26	LGIA Cancellations: Superseded Great River Hydro LGIAs (Moore, Vernon, Comerford) (ER20-2897 et al.)	Oct 29-30	FERC accepts notices of cancellation of LGIAs between NEP and Great River Hydro governing the interconnection of the three hydro facilities: (i) Moore (ER20-2897) (eff. Dec 10, 2018); (ii) Vernon (ER20-2896) (eff. May 8, 2019); and (iii) Comerford (ER20-2815) (eff. Aug 7, 2020)
*	26	Use Rights Transfer Agreement: NSTAR/HQ US (MMWEC) (ER20-2776)	Oct 9	FERC accepts Transfer Agreement for the Nov 1, 2020 to Oct 31, 2025 period; eff. Oct 31, 2020
*	26	Use Rights Transfer Agreement: NSTAR/HQ US (CMEEC) (ER20-2774)	Oct 9	FERC accepts Transfer Agreement for the Nov 1, 2020 to Oct 31, 2025 period; eff. Oct 31, 2020
*	26	Use Rights Transfer Agreement: NSTAR/HQ US (ENE) (ER20-2773)	Oct 9	FERC accepts Agreement for the transfer of CMEEC's Phase I/II HVDC Use Rights to HQ US for the Nov 1, 2020 to Dec 31, 2023 period, eff. Sep 26, 2020
	27	Use Rights Transfer Agreement: NSTAR/HQ US (ER20-2724)	Oct 9	FERC accepts Agreement, eff. Nov 1, 2020
	27	TSAs: Second Amendments to New England Clean Energy Connect TSAs (ER20-2674 et al.)	Oct 9	FERC accepts second amendments, eff. Oct 14, 2020

	27	VTransco Rate Schedule Cancellations (ER20-2507)	Oct 2	FERC accepts cancellations, eff. Jul 30, 2020
	27	VTransco VTA Waiver Request Clarification (ER20-1823-001)	Oct 20	FERC grants clarification requested (waiver should be viewed as a request to defer and amortize *up to* $10 million of the difference between the budgeted and actual ISO-NE RNS revenues over a 24-month period, beginning Jan 1, 2021)
	27	Phase II VT DMNRC Support Agreement *Order 864*-Related Filing (ER20-1480)	Oct 23	FERC accepts filing, eff. Jan 27, 2020
*	28	FERC Enforcement Action: High Desert (IN20-6)	Oct 23	FERC approves Stipulation and Consent Agreement with High Desert, requiring High Desert to pay a ***$390,000 civil penalty*** and to ***disgorge $176,000***, including interest, to resolve the FERC's investigation into violations, between Aug and Oct 2016, of the FERC's Anti-Manipulation Rules

XII. Misc. - Administrative & Rulemaking Proceedings

*	29	Offshore Wind Integration in RTOs/ISOs (Oct 27, 2020) (AD20-18)	Oct 27 Oct 29	FERC convenes tech conf. Speaker comments posted in eLibrary
	29	Carbon Pricing in RTO/ISO Markets Tech Conf (Sep 30, 2020) (AD20-14)	Sep 30 Oct 5 Oct 15	FERC convenes tech conf. Speaker opening remarks and comments posted in eLibrary FERC issues ***Notice of Proposed Policy Statement*** "to clarify FERC's jurisdiction over RTO/ISO market rules that incorporate a state-determined carbon price and to encourage RTO/ISO efforts to explore and consider the benefits of potential [] section 205 filings to establish such rules"; comment date Nov 16; reply comments due Dec 1
	30	Hybrid Resources Tech Conf (Jul 23, 2020) (AD20-9)	Oct 1	Post-tech conf comments filed by EPRI and PJM
*	31	RTO/ISOs Common Performance Metrics (AD19-16)	Oct 30	ISO-NE files FERC Form-922 – RTO/ISO Common Performance Metrics
	34	*Order 2222*: DER Participation in RTO/ISO Markets (RM18-9)	Oct 16-20 Oct 29	Excel Energy Services, Kansas Corp. Comm., AEE and AEMA, and Public Interest Organizations request rehearing of *Order 2222*; FERC action required by Nov 16, 2020 FERC publishes notice of correction: deadline to submit *Order 2222* compliance filings is Jul 19, 2021
	36	NOPR: NAESB WEQ Standards v. 003.3 - Incorporation by Reference into FERC Regs (RM05-5-029, -030)	Nov 3	BPA, EEI, the IRC, and Open Access Technology International file comments

XIII. Natural Gas Proceedings

	41	Iroquois ExC Project (CP20-48)	Sep 30 Oct 1 Oct 7 Oct 27-Nov 2	FERC issues Environmental Assessment ("EA") Report for ExC Project FERC issues data request regarding A&G Expenses Iroquois responds to Oct 1 data request Over 22 sets of comments filed in response to EA
	41	Northern Access Project (CP15-115)	Nov 16 Oct 26-Nov 3	Applicants request an additional 2-year extension of time, until Dec 1, 2024, to complete construction of the Project and enter service; comment date Nov 6, 2020 Over 30 sets of comments filed on requested extension

XIV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XV. Federal Courts

*	43	ISO-NE Implementation of Order 1000 Exemptions for Immediate Need Reliability Projects (20-1422)	Oct 16	LS Power petitions 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
			Oct 20	Clerk issues order requiring appearances, docketing statements and statement of issues by Nov 19; dispositive motions, if any, and a Certified Index to the Record, by Dec 4, 2020
	44	Mystic 8/9 Cost of Service Agreement (20-1343 et al. (consol.)	Oct 6-8	Parties file appearances, statement of issues
			Oct 8, 16	Petitioners file statements of issues and docketing statements
			Oct 16	FERC files unopposed motion to hold this appeal in abeyance until the earlier of Dec 15, 2020 (60 days) or the date of the issuance by the FERC of a further order on rehearing
	44	CASPR (20-1333)	Oct 2	Petitioners file docketing statement and statement of issues
			Oct 19	FERC moves to dismiss case for lack of jurisdiction or, alternatively for a 60-day abeyance to allow for the FERC to issue an order on the rehearing requests filed in 2018
			Oct 29	Petitioners oppose the FERC's Oct 19 motion
	44	*Opinion 531-A* Compliance Filing Undo (20-1329)	Sep 30	Parties file appearances, docketing statement, statement of issues
			Oct 2	Court grants FERC request to hold this proceeding in abeyance for four months; directs parties to file motions to govern future proceedings in this case by Feb 2, 2021
	45	2013/14 Winter Reliability Program Order on Compliance and Remand (20-1289, 20-1366) (consol.)	Oct 15	NEPGA intervenes
			Oct 16	TransCanada files docketing statement, statement of issues
			Oct 29	FERC files certified index to the record; motion for 60-day briefing interval
	45	ISO-NE's Inventoried Energy Program (Chapter 2B) Proposal (19-1224)	Oct 19-20	Petitioners each file amended petitions for review in order to bring the FERC's *IEP Remand Order* and the post-remand record before the DC Circuit
	45	*Order 872* (20-72728) (9th Cir.)	Oct 9	FERC files unopposed motion for the Court to hold this appeal in abeyance, suspend filing of the certified index to the record, and issue a new briefing schedule after Jan 4, 2021
			Oct 26	Court grants FERC's motion, suspended briefing, and directed the FERC to file a status report on or before Jan 4, 2021
	46	*Allegheny Defense Project v. FERC* (17-1098)	Oct 6	Mandate issued to the FERC
	46	FERC orders on PG&E Bankruptcy (19-71615) (9th Cir.)	Oct 7	Court dismisses PG&E's petition for review (No. 19-71615) with instructions for the FERC to vacate its orders and dismissed FERC's consolidated appeal (Nos. 19-16833, 19-16834) with instructions for the bankruptcy court to vacate its order
	48	Opinion 569/569-A: FERC's Base ROE Methodology (16-1325) (consol.)	Oct 27	Court consolidates cases and indicates that a schedule for the filing of briefs will be established by future order

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: November 4, 2020

RE: Status Report on Current Regional Wholesale Power and Transmission Arrangements Pending Before the Regulators, Legislatures and Courts

We have summarized below the status of key ongoing proceedings relating to NEPOOL matters before the Federal Energy Regulatory Commission ("FERC"),[1] state regulatory commissions, and the Federal Courts and legislatures through November 4, 2020. If you have questions, please contact us.

COVID-19

- **Jul 8-9 Tech Conf: Impacts of COVID-19 on the Energy Industry (AD20-17)**

On July 8-9, 2020, the FERC convened a Commissioner-led technical conference to explore the potential longer-term impacts of the emergency conditions caused by COVID-19 on FERC-jurisdictional entities "in order to ensure the continued efficient functioning of energy markets, transmission of electricity, transportation of natural gas and oil, and reliable operation of energy infrastructure today and in the future, while also protecting consumers". The conference included consideration of: (i) the energy industry's ongoing and potential future operational and planning challenges due to COVID-19 and as the situation evolves moving forward; (ii) the potential impacts of changes in electric demand on operations, planning, and infrastructure development; (iii) the potential impacts of changes in natural gas and oil demand on operations, planning, and infrastructure development; and (iv) issues related to access to capital, including credit, liquidity, and return on equity. Comments and speaker opening statements are posted in eLibrary.

Interested parties were invited to file, on or before August 31, 2020, post-technical conference comments on any or all of the topics discussed at the July 8-9 technical conference, as well as to respond to the questions outlined in the July 1, 2020 supplemental notice of technical conference. Comments were filed by AEP, APPA, America Forest & Paper, America's Power, EEI, IEEE Power & Energy Society, Clearview Energy Partners, TAPS, Assoc. of Oil Pipelines, Pilot Travel Centers, and Process Gas. This matter is pending before the FERC.

- **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

[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).

for Participants" was revised on September 23, 2020 to make three 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)**

The wavier of FERC regulations that require that filings with the FERC be notarized or supported by sworn declarations is ***in effect through January 29, 2021***.[5] The August 20 notice extended the waiver first noticed in May.[6] As previously reported, Entities may also seek waiver of FERC orders, regulations, tariffs and rate schedules, including motions for waiver of regulations that govern the form of filings, as appropriate, to address needs resulting from steps they have taken in response to the coronavirus.[7]

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

The extension of the blanket waivers of ISO/RTO Tariff *in-person*[8] meeting and notarization requirements has similarly been ***extended through January 29, 2021***.[9] The August 20, 2020 order extended the blanket waivers first granted in the FERC's April 2, 2020 order.[10]

I. Complaints/Section 206 Proceedings

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

On October 13, 2020, NECEC Transmission LLC ("NECEC") and Avangrid Inc. (together, "Avangrid") filed a complaint against NextEra[11] requesting FERC action "to stop NextEra from unlawfully interfering with the interconnection of the New England Clean Energy Connect transmission project ("NECEC Project")." The Complaint seeks, among other things, an initial, expedited order that grants certain relief[12] and directs 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. Comments on the Complaint were due on or before November 2, 2020. On November 2, National Grid filed comments. Doc-less interventions were filed by Dominion, Eversource, Calpine, Exelon, HQ US, MA AG, MMWEC National Grid, NESCOE, NRG, Public Citizen. 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).

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[4] *Chief Administrative Law Judge's Notices to the Public*, Docket No. AD20-12 (Sep. 23, 2020) (removing law clerk requirement to share screen when moving exhibits, revising procedures for requesting Live Litigation, and revising witness communication guidance to require that "[c]ommunications with a witness through concealed channels of communications are prohibited while the witness is providing testimony on the witness stand. Communications with a witness are allowed during breaks and when they are not on the witness stand.")

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

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

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

[8] 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).

[9] *Temporary Action to Facilitate Social Distancing*, 172 FERC ¶ 61,151 (Aug. 20, 2020).

[10] *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).

[11] For purposes of this Complaint proceeding, "NextEra" is short for NextEra Energy Resources, LLC ("NextEra Energy Resources"), NextEra Energy Seabrook, LLC ("NextEra Seabrook"), FPL Energy Wyman LLC ("Wyman"), and FPL Energy Wyman IV LLC ("Wyman IV").

[12] 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.

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

In a related matter initiated a week earlier, 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 due on or before November 4, 2020, and were, at least as of the issuance of this Report, filed by Eversource and MMWEC. Doc-less interventions were filed by Avangrid, Dominion, Eversource, Calpine, Exelon, HQ US, National Grid, NESCOE, NRG, and Public Citizen. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **New England Generators' Exelon Complaint (EL20-67)**

On August 25, 2020, New England Generators[13] filed a complaint against Exelon[14] requesting that, if and to the extent the FERC does not grant all relief requested by the New England Generators in its August 27, 2020 request for clarification and/or rehearing of the *July 17 Orders* in the Mystic 8/9 Cost of Service Agreement ("COS Agreement") proceeding (*see* ER18-1639 below), the FERC should find that the new information about Exelon's two new queue positions and Exelon's intention to continue to operate Everett beyond the term of the Mystic Agreement makes the existing rate in the Mystic Agreement unjust and unreasonable. New England Generators further requested that the FERC change the Mystic Agreement to: (i) apply the clawback mechanisms to Exelon's two new interconnection queue positions (to prevent Exelon from using interconnection queue positions for "new" or "repowered" units to skirt restrictions imposed on Mystic's recovery of costs pursuant to the COS Agreement); (ii) delete or give no meaning to the words "that were expensed" (in order to prevent Exelon from shielding costs paid for by captive ratepayers from the application of the COS Agreement's clawback provision); and (iii) require that Mystic return any of the undepreciated Everett repair and capital expenditure costs in the event that Mystic 8 or 9 return to the market after the end of the COS Agreement.

Exelon's answer and all interventions, or protests were due on or before September 14, 2020. In addition to Exelon's answer, comments supporting the Complaint were filed by NESCOE, Public Systems[15] and Connecticut Parties.[16] On September 28, NEPGA answer Exelon's answer. Interventions only were filed by Calpine, Energy New England ("ENE"), Eversource, Massachusetts Attorney General ("MA AG") National Grid, and Public Citizen. The Complaint, as well as all of the pleadings in response, remain pending before the FERC. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

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[13] "New England Generators" are Vistra, Dynegy Marketing and Trade, NextEra Energy Resources, NRG Power Marketing, LS Power Associates, FirstLight Power, and Cogentrix Energy Power Management.

[14] For purposes of this Complaint, "Exelon" is short for Constellation Mystic Power, LLC ("Mystic"), Exelon Generation Company, LLC ("Exelon Generation") and Exelon Corporation ("Exelon Corp.").

[15] "Public Systems" are Mass. Municipal Wholesale Elec. Co. ("MMWEC") and New Hampshire Elec. Coop., Inc. ("NHEC").

[16] "Connecticut Parties" are CT PURA, CT DEEP, and the CT OCC.

- **206 Proceeding: FCM Pricing Rules Complaints Remand (EL20-54)**

In response to the February 2, 2018 remand by the United States Court of Appeals for the District of Columbia Circuit ("DC Circuit")[17] (where the DC Circuit found that the FERC did not adequately explain why it allowed ISO-NE to forego an offer floor for its seven-year price lock period despite previously rejecting PJM's request to remove the offer floor for its three-year price lock period), the FERC instituted this proceeding, pursuant to section 206 of the FPA, finding preliminarily that ISO-NE's new entrant rules may be unjust and unreasonable.[18] The FERC established paper hearing procedures and posed the following questions, which needed to be addressed in initial briefs due on or before ***August 24, 2020***:[19]

(a) ***to evaluate the need for the price lock in its entirety***: (i) how many resources have taken advantage of the price lock to date? (ii) is a price lock still needed to incent new entry in ISO-NE? (iii) does the price lock lead to unreasonable price suppression in the entry year? (iv) does the price lock with the zero-price offer rule result in unreasonable price suppression in years 2-7? (v) is the price lock unduly discriminatory? and (vi) if the price lock is retained, should the term be shortened and, if so, what would be a just and reasonable term?

(b) ***to evaluate retaining the price-lock and adding an offer floor***: (i) how would an offer floor be implemented? (2) would an offer floor require significant market redesign? and (iii) what would be the timeline for implementing an offer floor in ISO-NE?

(c) ***to evaluate whether to impose an alternative replacement rate***: (i) are there alternative approaches to the current price-lock that would be sufficient to incent new entry? (ii) how would these alternative approaches address any concerns related to unreasonable price suppression? and (iii) how would these alternative approaches address any concerns related to undue discriminatory or preferential treatment?

Interventions were due on or before July 22, 2020 and were filed by NEPOOL, ISO-NE, ISO-NE EMM, Avangrid, Brookfield, BSW Project Co. (out-of-time), Calpine, CPV Towantic, Dominion, ENE, Eversource, Exelon, FirstLight, HQ US, LS Power, MA AG, MMWEC, National Grid, NESCOE, NHEC, NextEra, NRG, NTE Energy, Talen, Vistra, NEPGA, EPSA, CT AG, CT DEEP, CT PURA, MA DPU (out-of-time), PJM IMM, Public Citizen, RENEW Northeast (out-of-time), and Energy Storage Association ("ESA") (out-of-time).

Initial briefs were filed by ISO-NE, ISO-NE External Market Monitor ("EMM"), MA AG, NEPGA, NRG, and RENEW Northeast. NEPOOL filed limited comments (urging the FERC, should it conclude that the Tariff is unjust and unreasonable and/or unduly discriminatory, to allow sufficient time and flexibility to permit meaningful opportunities for New England stakeholders to work with ISO-NE to develop any required market adjustments through the complete NEPOOL Participant Processes).

Responses to the initial briefs were due September 23, 2020 and were filed by ISO-NE, BSW Project Co, MA AG, NEPGA, MA AG, CT PURA, PJM IMM, and RENEW/ESA. No additional answers or briefs will be permitted. This matter is again pending before the FERC.

In order to accept the changes originally filed, the FERC must provide some analysis and explanation why it changed course. The FERC established July 9, 2020 (the date of publication in the *Federal Register*) as the refund effective date. The FERC noted its expectation that it would issue a final order in this proceeding within the 180-

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[17] *New England Power Generators Assoc. v FERC*, 881 F.3d 202 (DC Cir. 2018) (granting NEPGA's and Exelon's petitions for review of orders accepting the Forward Capacity Market's ("FCM") 7-year price lock-in (EL14-7) and capacity-carry-forward rules (EL15-23)).

[18] *ISO New England Inc.*, 172 FERC ¶ 61,005 (July 1, 2020) ("*FCM Pricing Rules Complaints Remand Order*").

[19] Notice of the initiation of this proceeding was published in the *Fed. Reg.* on July 9, 2020 (Vol. 85, No. 132) p. 41,237. Aug. 24, 2020 was the first Business Day that was 45 days after publication.

day period contemplated under FPA section 206(b). If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **Exelon PP-10 Complaint (EL20-52)**

On October 19, 2020, the FERC issued a "Notice of Denial of Rehearing by Operation of Law".[20] The Notice confirmed that the 60-day period during which a petition for review of the FERC's July 17 Orders can be filed with an appropriate federal court was triggered when the FERC did not act on Exelon's September 16, 2020 request for rehearing of the FERC's order denying Constellation Mystic Power, LLC's ("Exelon") June 10, 2020 complaint ("PP-10 Complaint").[21]

As previously reported, the PP-10 Complaint requested that ISO-NE be prohibited from (i) implementing changes to the Planning Procedure to Support the Forward Capacity Market ("PP-10"),[22] which Exelon asserted would significantly affect the rates, terms and conditions of jurisdictional services by dramatically changing the way in which ISO-NE conducts its annual transmission security review of capacity auction retirement bids and the Network Model upon which the capacity auction is based, and (ii) violating the requirements of its Tariff for *Order 1000* competitive transmission procurements. In denying the Complaint, the FERC found that it is Tariff § III.13.2.5.2.5(e), and not the PP-10 Revisions, which significantly affects the rates, terms and conditions of service that concern Mystic.[23] The PP-10 Revisions, which are similar to the "instructions [and] guidelines . . . [that] guide internal operations" that the FERC has found to be more appropriately placed in non-tariff materials,[24] did not need to be included in the Tariff under the FERC's rule of reason policy. The FERC disagreed with Mystic's assertion that the Tariff requires ISO-NE to use the Network Model for the transmission security review for a resource that has previously submitted a Retirement De-List Bid, finding "the Boston RFP results provide ISO-NE with sufficient information to ensure that it can address violations of applicable reliability criteria due to the absence of Mystic 8 and 9 and had no need to use the Network Model in order to comply with Tariff section III.13.2.5.2.5."[25] In addition, the FERC found that the PP-10 Revisions did not violate the Attachment K provisions related to the *Order 1000* RFP process,[26] that Mystic failed to demonstrate that ISO-NE violated its Tariff in conducting the Boston RFP process,[27] or that the PP-10 Revisions jeopardize reliability.[28]

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).

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[20] *Constellation Mystic Power, LLC v. ISO New England Inc.*, 173 FERC ¶ 62,034 (Oct. 19, 2020).

[21] *Constellation Mystic Power, LLC v. ISO New England Inc.*, 172 FERC ¶ 61,144 (Aug. 17, 2020) ("*Order Denying PP-10 Complaint*"), *reh'g denied by operation of law,* 173 FERC ¶ 62,034 (Oct. 19, 2020).

[22] The PP-10 Revisions were supported by the Participants Committee at its June 4 meeting by a vote of 99.12% in support (only Exelon opposing).

[23] *Id.* at P 29.

[24] *Id.* at P 31.

[25] *Id.* at P 42.

[26] *Id.* at P 57.

[27] *Id.* at P 58.

[28] *Id.* at PP 69-71.

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

On October 16, 2020, LSP Transmission Holdings I, LLC ("LS Power") petitioned the DC Circuit Court of Appeals for review of the FERC's orders in this proceeding.[29] Reporting on this matter will move to Section XV. If you have any questions concerning this proceeding, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **RNS/LNS Rates and Rate Protocols Settlement Agreement II (ER20-2054; EL16-19-002)**

The uncontested Joint Offer of Settlement ("Settlement Agreement II") filed by the Transmission Owners to resolve all issues in this proceeding,[30] certified by Presiding ALJ Coffman to the Commission,[31] remains pending before the Commission.[32] 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,[33] 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*).[34] However, the FERC's orders were challenged, and in *Emera Maine,*[35] the DC Circuit

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[29] *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); *ISO New England Inc.*, 172 FERC ¶ 61,096 (Aug. 20, 2020) (notice of denial of rehearings by operation of law); and *ISO New England Inc.*, 172 FERC ¶ 61,293 (Sep. 29, 2020) ("*Order 1000 Exemptions Allegheny Order*").

[30] Recall that, as previously reported, the first joint offer of settlement filed ("Settlement Agreement I") proposed changes to Section II.25, Schedules 8 and 9, Attachment F (including the addition of Interim Formula Rate Protocols ("Interim Protocols")), and the Schedule 21s to the ISO-NE OATT. The Interim Protocols, as well as the changes to Section II.25 and Schedules 8 and 9, were supported by the Participants Committee at its July 24, 2018 meeting. However, Settlement Agreement I was contested by FERC Trial Staff and "Municipal PTF Owners" (Braintree, Chicopee, Middleborough, Norwood, Reading, Taunton, and Wallingford) and subsequently rejected by the FERC. *ISO New England Inc. Participating Transmission Owners Admin. Comm., et al.*, 167 FERC ¶ 61,164 (May 22, 2019) ("*RNS Rate/Rate Protocol Settlement I Order*") (finding (i) the ISO-NE Tariff unjust, unreasonable, and unduly discriminatory or preferential because the Tariff "lacks adequate transparency and challenge procedures with regard to the formula rates" for Regional Network Service ("RNS") and Local Network Service ("LNS"); and (ii) the RNS and LNS rates themselves "unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful" because "the formula rates appear to lack sufficient detail in order to determine how certain costs are derived and recovered in the formula rates" and "could result in an over-recovery of costs" due to the "the timing and synchronization of the RNS and LNS rates").

[31] *ISO New England Inc. Participating Transmission Owners Admin. Comm.*, 172 FERC ¶ 63,017 (Aug. 18, 2020).

[32] The Tariff changes included with Settlement Agreement II were considered through the Participants Processes (Transmission and Participants Committee review), and supported by the Participants Committee at its June 4, 2020 meeting (Agenda Item # 13). NEPOOL filed comments supporting the Tariff changes included with Settlement Agreement II. FERC Trial Staff filed comments not opposing Settlement Agreement II. The TOs filed reply comments supporting Settlement Agreement II.

[33] 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*")).

[34] *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*").

[35] *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

vacated the FERC's prior orders, and remanded the case for further proceedings consistent with its order. The FERC's determinations in *Opinion 531* are thus no longer precedential, though the FERC remains free to re-adopt those determinations on remand as long as it provides a reasoned basis for doing so.

- ***Base ROE Complaints II & III (EL13-33 and EL14-86) (consolidated)***. The second (EL13-33)[36] and third (EL14-86)[37] 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.[38] 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[39] also went to hearing before an ALJ, Judge Glazer, who issued his initial decision on March 27, 2017.[40] 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.[41] 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.[42] The FERC indicated its intention that the methodology be its policy going forward, including in

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(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).

[36] 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%.

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

[38] *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*").

[39] The 4th ROE Complaint asked the FERC to reduce the TOs' current 10.57% return on equity ("Base ROE") to 8.93% and to determine that the upper end of the zone of reasonableness (which sets the incentives cap) is no higher than 11.24%. The FERC established hearing and settlement judge procedures (and set a refund effective date of April 29, 2016) for the 4th ROE Complaint on September 20, 2016. Settlement procedures did not lead to a settlement, were terminated, and hearings were held subsequently held December 11-15, 2017. The September 26, 2016 order was challenged on rehearing, but rehearing of that order was denied on January 16, 2018. *Belmont Mun. Light Dept. v. Central Me. Power Co.*, 156 FERC ¶ 61,198 (Sep. 20, 2016) ("*Base ROE Complaint IV Order*"), *reh'g denied*, 162 FERC ¶ 61,035 (Jan. 18, 2018) (together, the "*Base ROE Complaint IV Orders"*). *The Base ROE Complaint IV Orders*, as described in Section XV below, have been appealed to, and are pending before, the DC Circuit.

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

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

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

the four currently pending New England proceedings (*see*, however, *Opinion 569-A*[43] (EL14-12; EL15-45) in Section XI below). The FERC established a paper hearing on how its proposed methodology should apply to the four pending ROE proceedings.[44]

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%.[45] 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[46] 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,

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

[44] *Id.* at P 19.

[45] *Id.* at P 59.

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

initial briefs were filed by EMCOS, Complainant-Aligned Parties, TOs, EEI, Louisiana PSC, Southern California Edison, and AEP. As part of their initial briefs, each of the Louisiana PSC, SEC and AEP also moved to intervene out-of-time. Those interventions were opposed by the TOs on January 24. The Louisiana PSC answered the TOs' January 24 motion on February 12. Reply briefs were due March 8, 2019 and were submitted by the TOs, Complainant-Aligned Parties, EMCOS, FERC Trial Staff.

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*[47] 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

- **2021 NESCOE Budget (ER21-113)**

This proceeding was initiated by ISO-NE's October 15, 2020 filing of the budget for funding NESCOE's 2021 operations. The 2021 Operating Expense Budget for NESCOE is $2,428,300. The amount to be recovered reflects true-ups from 2019 (over-collections of $1,067,405). Accordingly, if accepted, the NESCOE budget will result in a charge of $0.00626 per kilowatt ("kW") of Monthly Network Load. The 2021 NESCOE budget was supported by the Participants Committee at its October 1, 2020 meeting. Comments and any interventions are due on or before November 5. Thus far, NEPOOL intervened and filed comments supporting NESCOE's 2021 Budget, and NESCOE and National Grid submitted doc-les interventions. If there are any questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **2021 ISO-NE Administrative Costs and Capital Budgets (ER21-106)**

On October 15, 2020, ISO-NE filed for recovery of its 2021 administrative costs (the "2021 Revenue Requirement") and submitted its capital budget and supporting materials for calendar year 2021 ("2021 Capital Budget", and together with the 2021 Revenue Requirement, the "2021 ISO Budgets"). The 2021 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 2021 Revenue Requirement is $205 million, which increases to $205.1 million after the under-collection for 2019 is added. Of that total, ISO-NE's administrative costs (i.e., the 2021 Core Operating Budget) comprise $178.6 million; depreciation and amortization of regulatory assets, $26.3 million; and a $151,000 true-up for 2019 under-collections.

ISO-NE further reported that the 2021 Capital Budget, like the 2020 Capital Budget, is $28 million and is comprised of the following (with 2021 projected costs and target completion dates, if available, in parentheses):

- nGem Market Clearing Engine Implementation (Mar 2023) ($5.3 million)
- Energy Security Improvements ($3.0 million)

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

- nGem Software Development Part II (Dec 2021) ($2.0 million)
- 2021 Issue Resolution Projects (June 2021 and Dec 2021) ($1.5 million)
- Enhanced Market Simulator ($1.5 million)
- Forward Capacity Tracking System Infrastructure Conversation Part II (Jun 2021) ($1 million)
- Identity and Access Management – Phase II (May 2021) ($700,000)
- Data Governance, Risk Management & Compliance Software Phase I (Jun 2021) ($400,000)
- IMM Data Analysis Phase III (Nov 2021) ($500,000)
- Sub-accounts for FTR Market (Aug 2021) ($500,000)
- TranSMART Technical Architecture Update (Dec 2021) ($500,000)
- FERC Form 1, 3-Q, 714 (Oct 2021) ($200,000)
- Wireless Infrastructure Upgrade (Jun 2021) ($200,000)
- 2020 Issue Resolution Projects (Mar 2021) ($100,000)
- Forward Capacity Tracking System Infrastructure Conversation Part II (Dec 2020) ($2 million)
- 2020 Corrective Action Preventative Actions (Mar 2021) ($100,000)
- CIP Electronic Security Perimeter Redesign ($1 million)
- Cyber Security Improvements (Sep 2021) ($1 million)
- Enterprise Application Integration Phase III (Nov 2021) ($500,000)
- Data Governance, Risk Management & Compliance Software Phase II (Nov 2021) ($500,000)
- Human Resources Workflow & Document Management (Jun 2021) ($500,000)
- Security Information and Event Management Log Monitoring ($500,000)
- PI Historian for Short-term PMU Data Repository (Jun 2021) ($300,000)
- External Website Migration to Cloud (Mar 2021) ($100,000)
- Non-Project Capital Expenditures ($3.5 million)
- Other Emerging Work ($1.9 million)
- Capitalized Interest ($500,000)

The 2021 ISO-NE Budgets were supported by the Participants Committee at its October 1, 2020 meeting. Comments on this filing are due November 5, 2020. NEPOOL filed comments supporting the 2021 Budgets on October 28. Doc-less interventions only have thus far been filed by MA AG, National Grid and NESCOE. If there are any questions on this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

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

As previously reported, the FERC issued four orders in this proceeding in July 2020 (three on July 17 (together, the "*July 17 Orders*"); one on July 28, 2020). Each of the orders addressed in part or in whole the Cost-of-Service Agreement ("COS Agreement")[48] among Constellation Mystic Power ("Mystic"), Exelon

[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, and on the continued provision of surplus LNG from Distrigas to third parties.

Generation Company ("ExGen") and ISO-NE, which is to provide compensation for the continued operation of the Mystic 8 & 9 units from June 1, 2022 through May 31, 2024. As noted in Section XV below, each of the *July 17 Orders*[49] (and the earlier, underlying orders) have been appealed to the DC Circuit.

ROE Paper Hearings (-000). The *Dec 2018 Order* established a paper hearing to determine the just and reasonable ROE to be used in setting charges under Mystic's COS Agreement. On April 19, 2019, Mystic, Connecticut Parties, ENECOS, MA AG, and FERC Trial Staff filed initial briefs. On July 18, 2019, Constellation Mystic Power, CT Parties, ENECOS, MA AG, National Grid, FERC Trial Staff filed reply briefs. In a July 28, 2020 order,[50] the FERC reopened the record to allow parties an opportunity to present written evidence applying the FERC's *Opinion 569-A* ROE methodology to the facts of this proceeding. CT Parties, EMCOS, MA AG, and FERC Trial Staff filed their initial "Opinion 569-A" briefs on September 28, 2020. Responses to those initial briefs were due October 28, 2020 and were filed by Mystic, CT Parties, ENECOS, and FERC Trial Staff. The ROE issue is now pending before the Commission.

Sep 2020 Compliance Filing (-007). On September 15, 2020, Mystic filed a revised COS Agreement in response to the requirements of the *July 17 Compliance Order*. Also included were typographical edits proposed by NESCOE in its protest of the First Compliance Filing. Mystic also filed revisions to the Fuel Security Agreement ("FSA") for informational purposes because some of the compliance directives required changes to the FSA. Comments on the Sep 2020 Compliance Filing were due on or before October 6, 2020. CT Parties and ENECOS protested the compliance filing. On October 21, Mystic answered the CT Parties' and ENECOS' protests. The compliance filing is 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

- **Gross Load Forecast Reconstitution Revisions (ER20-2869)**

On October 30, the FERC accepted changes jointly filed by ISO-NE and NEPOOL (i) to improve the methodology that ISO-NE uses to reconstitute On-Peak Demand Resources and Seasonal Peak Demand Resources (collectively, "Passive Demand Resources") in the long-term gross load forecast; and (ii) to delete obsolete language in Section III.12.8 (b), and make conforming, non-substantive changes in the preamble of Section III.12.8 – Load Modeling Assumptions (together, the "Gross Load Forecast Reconstitution Revisions").[51] The Gross Load Forecast Reconstitution Revisions were accepted effective as of November 10, 2020, as requested. Unless the October 20 order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **ESI Alternatives (ER20-1567)**

On October 30, 2020, the FERC rejected as unjust and unreasonable both the ISO-NE and NEPOOL "Energy Security Improvements" or "ESI" proposals.[52] Finding that ISO-NE failed to demonstrate that ESI will materially

[49] 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).

[50] *Constellation Mystic Power, LLC*, 172 FERC ¶ 61,093 (July 28, 2020).

[51] *ISO New England Inc. and the New England Power Pool Participants Comm.*, Docket No. ER20-2869 (Oct. 30, 2020) (unpublished letter order).

[52] ISO New England Inc., 173 FERC ¶ 61,106 (Oct. 30, 2020) ("*Order Rejecting ESI Alternatives*").

improve fuel security, and treating the filing as submitted under FPA section 205,[53] the FERC concluded that "ESI does not strike an appropriate balance between addressing fuel security in New England while protecting consumers from the significant cost of those fuel security benefits."[54] And, although the FERC noted that the NEPOOL Alternative would result in lower costs to consumers than ISO-NE's ESI proposal, they rejected the NEPOOL Alternative as unjust and unreasonable because it contained the "same deficiencies that render ISO-NE's proposal unjust and unreasonable."[55]

Because the FERC rejected both alternative ESI proposals, the FERC also rejected ISO-NE's associated proposal to sunset one year earlier than currently provided for in the Tariff the Fuel Security Retention Mechanism and the Inventoried Energy Program (the Interim Programs).[56]

The FERC made no finding on whether ISO-NE faces a fuel security or energy security issue,[57] but said ISO-NE may propose "other steps it believes are warranted to address fuel security, such as submitting a revised long-term fuel security proposal or seeking to extend one or more of the Interim Programs."[58] While the FERC did not direct ISO-NE to pursue any particular approach, if ISO-NE decides to pursue a solution to address their concerns, it encouraged ISO-NE:

> "to explore a market-based reserve product that provides resources sufficient lead time and ability to acquire fuel or take other steps necessary to be able to deliver energy when needed. We expect that such a market solution would be designed to (1) coordinate procurement of forward reserves with co-optimization of energy and reserves in the day-ahead and real-time markets; (2) incentivize resources to offer into the forward, day-ahead and real-time energy and reserves markets based on their actual costs; (3) prevent the exercise of market power, including through mitigation measures, if necessary; and (4) include financial obligations or incentives sufficient to ensure resources can deliver energy and/or reserves in real-time."[59]

The FERC noted that nothing in its order prohibits ISO-NE from proposing a Day-Ahead reserves market independent of any proposal to address the concerns at issue in the ESI proceeding.[60]

Challenges to the *Order Rejecting ESI Alternatives* are due on or before November 30, 2020. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

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

On October 16, 2020, the FERC formally dismissed as moot Vineyard Wind's December 14, 2018 petition for a waiver of the ISO-NE Tariff provisions necessary to allow Vineyard Wind to participate in FCA13

[53] *Id.* at n. 2. The April 15, 2020 ESI filing was submitted in response to the requirements of the *Mystic Waiver Order*, which directed ISO-NE, in part, to submit permanent Tariff revisions reflecting improvements to its market design to better address regional fuel security concerns. *See ISO New England Inc.*, 164 FERC ¶ 61,003 (July 2, 2018), *reh'g requested* ("*Mystic Waiver Order*").

[54] *Id.* at P 55.

[55] *Id.* at P 56.

[56] *Id.* at P 63.

[57] *Id.* at P 57.

[58] *Id.* at P 63.

[59] *Id.* at P 57.

[60] *Id.*

as an RTR.[61] As previously reported, Vineyard Wind's request for RTR designation was rejected by ISO-NE on the basis that the resource is to be located in federal waters. Consistent with the discussion in the CASPR Conforming Changes filing, Vineyard Wind asked that the proration requirement that would be triggered by Vineyard Wind's participation in FCA13 as an RTR be limited for FCA13 to it and any other similarly-situated entities (i.e. new offshore wind resources located in federal waters seeking RTR treatment). Despite several last minute requests to do so, including a Vineyard Wind emergency motion for immediate stay of FCA13 or, in the alternative, a requirement that FCA13 be re-run following FERC action, the FERC took no action ahead of FCA13 and FCA13 was run without Vineyard Wind receiving RTR treatment. In the October 16, 2020 order, the FERC, finding that the "circumstances render Vineyard Wind's requested waiver moot", dismissed the request.[62] If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- ***Order 841* Compliance Filings (Electric Storage in RTO/ISO Markets) (ER19-470)**

As previously reported, the FERC has now conditionally accepted both the November 22, 2019[63] and February 10, 2020[64] *Order 841*[65] compliance filings, each subject to additional compliance filing(s). In its most recent order, the *Order 841 Compliance Filing II Order*, the FERC directed that the following be addressed in further compliance (now due on or before December 7, 2020, as described below):

- ***Application of Transmission Charges***. ISO-NE directed to file proposed Tariff revisions: (i) specifying that it will not apply transmission charges to electric storage resources when they are dispatched to withdraw energy to provide voltage support and reactive control, provide operating reserves, provide regulation, balance energy supply and demand on an economic basis, or address a reliability concern; and (ii) applying transmission charges to electric storage resources when they are not being dispatched to provide one of those tariff-defined services.[66]
- ***ISO-NE Market Participation***. Section III.1.10.6(d)(ii) must be modified to either (i) eliminate any suggestion that a host utility could be allowed, through an unwillingness to support the necessary registration, metering, and accounting of the electric storage resource, to decide whether an electric storage resource may participate in the ISO-NE markets; or (ii) to clarify how the section does not serve as a barrier to the participation of electric storage resources.
- ***State of Charge and Duration Characteristics in the Day-Ahead Energy Market.*** Tariff Section III.1.10.6(d) must be modified to specify how ISO-NE will account for State of Charge and Duration Characteristics of electric storage resources in the Day-Ahead Energy Market. If new bidding parameters will be relied on, the Tariff must define those bidding parameters and the transmittal letter must explain how those bidding parameters will be incorporated into the Day-Ahead Energy Market engine. If "other means" will be relied on, the Tariff must specify those other means with sufficient detail and the transmittal letter must explain how those other means will account for State of Charge and Duration Characteristics of electric storage resources in the Day-Ahead Energy Market.

On September 10, 2020, the FERC accepted the joint request by NEPOOL and ISO-NE for a 35-day extension of time to submit all of the changes required by the *Order 841 Compliance Filing II Order* in one comprehensive compliance filing. That compliance filing must be filed on or before December 7, 2020, with plans for the Tariff changes to be proposed to be considered at the December 3 Participants Committee

[61] *Vineyard Wind LLC*, 173 FERC ¶ 61,058 (Oct. 1, 2020) (order rejecting waiver request as moot).

[62] *Id.* at P 14.

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

[64] *ISO New England Inc.*, 172 FERC ¶ 61,125 (Aug. 4, 2020) ("*Order 841 Compliance Filing II Order*").

[65] *See Elec. Storage Participation in Mkts. Operated by Regional Transmission Orgs. and Indep. Sys. Operators*, Order No. 841, 162 FERC ¶ 61,127 (Feb. 15, 2018) ("*Order 841*").

[66] *Order 841 Compliance Filing II Order* at P 52.

meeting (following completion of Markets Committee consideration; the Transmission Committee unanimously approved at its October 27 meting Participants Committee support for the pieces of the further compliance filing under its purview). If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Fuel Security Retention Proposal (ER18-2364)**

Requests for rehearing and/or clarification of the *Fuel Security Retention Proposal Order*[67] remain pending before the FERC. As previously reported, the *Fuel Security Retention Proposal Order* accepted ISO-NE's Proposal[68] in all respects, despite the various protests and alternative proposals filed. There was a concurring decision from Commissioner Glick, and a partial dissent from Chairman Chatterjee on the FCA price treatment issue. Challenges to the *Fuel Security Retention Proposal Order* were filed by NEPGA, NRG, Verso, Vistra/Dynegy Marketing & Trade, MPUC, and PIOs.[69] On February 1, 2019, the FERC issued a tolling order to afford it additional time to consider the requests for rehearing, which remain pending. There has been no substantive activity since the Last Report. If you have further questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **ISO-NE Waiver Filing: Mystic 8 & 9 (ER18-1509; EL18-182)**

On July 2, 2018, the FERC issued an order[70] that (i) denied ISO-NE's request for waiver of certain Tariff provisions that would have permitted ISO-NE to retain Mystic 8 & 9 for fuel security purposes (ER18-1509); and (ii) instituted an FPA Section 206 proceeding (EL18-182) (having preliminarily found that the ISO-NE Tariff may be unjust and unreasonable in that it fails to address specific regional fuel security concerns identified in the record that could result in reliability violations as soon as year 2022). The *Mystic Waiver Order* required ISO-NE, on or before August 31, 2018 to either: (a) submit interim Tariff revisions that provide for the filing of a short-term, cost-of-service agreement ("COS Agreement") to address demonstrated fuel security concerns (and to submit by July 1, 2019 permanent Tariff revisions reflecting improvements to its market design to better address regional fuel security concerns "Chapter 3 Proposal"); or (b) show cause as to why the Tariff remains just and reasonable in the short- and long-term such that one or both of Tariff revisions filings is not necessary.

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67 *ISO New England Inc.*, 165 FERC ¶ 61,202 (Dec. 3, 2018), *reh'g requested* ("*Fuel Security Retention Proposal Order*"). In accepting the ISO-NE Proposal, the FERC, among other things: (i) found ISO-NE's trigger and assumptions for the fuel security reliability review for retention of resources be reasonable, but required ISO-NE at the end of each winter to "to submit an informational filing comparing the study assumptions and triggers from the modeling analysis to actual conditions experienced in the winter of 2018/19; (ii) found cost allocation on a regional basis to Real-Time Load Obligation just and reasonable and consistent with precedent regarding the past Winter Reliability Programs; (iii) found that entering retained resources into the FCAs as price takers would be just and reasonable to ensure that they clear and are counted towards resource adequacy so that customers do not pay twice for the resource; and (Iv) found that it was appropriate to include FCAs 13, 14 and 15 in the term. The FERC agreed that it is necessary to implement a longer-term market solution as soon as possible, and required ISO-NE to file its longer-term market solution no later than June 1, 2019. The FERC declined to provide guidance on what the long-term solution(s) should be.

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

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

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

Addressing the waiver element, the FERC found the waiver request "an inappropriate vehicle for allowing Mystic 8 and 9 to submit a [COS Agreement] in response to the identified fuel security need" and further that the request "would not only suspend tariff provisions but also alter the existing conditions upon which a market participant could enter into a [COS Agreement] (for a transmission constraint that impacts reliability) and allow for an entirely new basis (for fuel security concerns that impact reliability) to enter into such an agreement." The FERC concluded that "[s]uch new processes may not be effectuated by a waiver of the ISO-NE Tariff; they must be filed as proposed tariff provisions under FPA section 205(d)."[71] Even if it were inclined to apply its waiver criteria, the FERC stated that it would still have denied the waiver request as "not sufficiently limited in scope."[72]

Although it denied the waiver request, the FERC was persuaded that the record supported "the conclusion that, due largely to fuel security concerns, the retirement of Mystic 8 and 9 may cause ISO-NE to violate NERC reliability criteria." Finding ISO-NE's methodology and assumptions in the Operational Fuel-Security Analysis ("OFSA") and Mystic Retirement Studies reasonable, the FERC directed the filing of both interim and permanent Tariff revisions to address fuel security concerns (or a filing showing why such revisions are not necessary).[73] The FERC directed ISO-NE to consider the possibility that a resource owner may need to decide, prior to receiving approval of a COS Agreement, whether to unconditionally retire, and provided examples of how to address that possibility.[74] The FERC also directed ISO-NE include with any proposed Tariff revisions a mechanism that addresses how cost-of-service-retained resources would be treated in the FCM[75] and an *ex ante* cost allocation proposal that appropriately identifies beneficiaries and adheres to FERC cost causation precedent.[76]

Requests for Rehearing and/or Clarification. The following requests for rehearing and or clarification of the *Mystic Waiver Order* remain pending before the FERC:

- ***NEPGA*** (requesting that the FERC grant clarification that it directed, or on rehearing direct, ISO-NE to adopt a mechanism that prohibits the re-pricing of Fuel Security Resources in the FCA at $0/kW-mo. or at any other uncompetitive offer price);
- ***Connecticut Parties***[77] (requesting that the FERC clarify that (i) the discussion in the *Mystic Waiver Order* of pricing treatment in the FCM for fuel security reliability resources is not a final determination nor is it intended to establish FERC policy; (ii) the FERC did not intend to prejudge whether entering those resources in the FCM as price takers would be just and reasonable; and (iii) that ISO-NE may confirm its submitted position that price taking treatment for these resources would, in fact, be a just and reasonable outcome. Failing such clarification, Connecticut Parties request rehearing, asserting that the record fails to support a determination that resources retained for reliability to address fuel security concerns must be entered into the FCM at a price greater than zero);
- ***ENECOS*** (asserting that the *Mystic Waiver Order* (i) misplaces reliance on ISO-NE "assertions concerning 'fuel security,' which do not in fact establish a basis in evidence or logic for initiating" a Section 206(a) proceeding; (ii) impermissibly relies on extra-record material that the FERC did not actually review and that intervenors were afforded no meaningful opportunity to challenge; and (iii) speculation concerning potential future modifications to the FCM bidding rules as to retiring generation retained for fuel security misunderstands the problem it seeks to address, and prejudices the already truncated opportunities for stakeholder input in this proceeding), ENECOS suggest that the FERC should grant rehearing, vacate its show cause directive, strike its dictum concerning potential

[71] *Id.* at P 47.

[72] *Id.* at P 48.

[73] *Id.* at P 55.

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

[75] *Id.* at P 57.

[76] *Id.* at P 58.

[77] "Connecticut Parties" are CT PURA and CT DEEP.

treatment of FCM bidding for retiring generation retained for "fuel security," and direct ISO-NE to proceed either in accordance with its Tariff or under FPA Section 205 to address, with appropriate evidentiary support, whatever concerns it believes to exist concerning "fuel security");

- ***MA AG*** (asserting that the decision to institute a Section 206 proceeding was insufficiently supported by sole reliance on highly contested OFSA and Mystic Retirement Studies; and the FERC should reconsider the timeline for the permanent tariff solution and set the deadline for implementation no later than February 2020);
- ***MPUC*** (challenging the Order's (i) adoption of ISO-NE's methodology and assumptions in the OFSA and Mystic Retirement Studies without undertaking any independent analysis; (ii) failure to address arguments and analysis challenging assumptions in the OFSA and Mystic Retirement Studies; (iii) failure to address the MPUC argument that the Mystic Retirement Studies adopted a completely new standard for determining a reliability problem three years in advance; (iv) unreasonably discounting of the ability of Pay-for-Performance to provide sufficient incentives to Market Participants to ensure their performance under stressed system conditions; and (v) failure to direct ISO-NE to undertake a Transmission Security Analysis consistent with the provisions in the Tariff);
- ***New England EDCs***[78] (requesting clarification that (i) the central purpose of ISO-NE's July 1, 2019 filing is to assure that New England adds needed new infrastructure to address the fuel supply shortfalls and associated threats to electric reliability that ISO-NE identified in its OFSA and (ii) that, in developing the July 1, 2019 filing, ISO-NE is to evaluate Tariff revisions (such as those the EDCs described in their request), through which ISO-NE customers would pay for the costs of natural gas pipeline capacity additions via rates under the ISO-NE Tariff);
- ***PIOs***[79] (asserting that (i) the FERC failed to respond to or provide a reasoned explanation for rejecting the arguments submitted by numerous parties that key assumptions underlying and the results of the ISO-NE analyses were flawed; and (ii) the FERC's determination that ISO-NE's analyses were reasonable is not supported by substantial evidence in the record); and
- ***AWEA/NGSA*** (asserting that the FERC erred (i) in finding that ISO-NE's OFSA and subsequent impact analysis of fuel security was reasonable without further examination and (ii) in its preliminary finding that a short-term out-of-market solution to keep Mystic 8 & 9 in operation is needed to address fuel security issues).

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

There has been no substantive activity since the Last Report. If you have any questions concerning this proceeding, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

[78] The "EDCs" are the National Grid companies (Mass. Elec. Co., Nantucket Elec. Co., and Narragansett Elec. Co.) and Eversource Energy Service Co. (on behalf of its electric distribution companies – CL&P, NSTAR and PSNH).

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

IV. OATT Amendments / TOAs / Coordination Agreements

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

On September 25, 2020, as amended on October 14, 2020, Cogentrix Energy Power Management, LLC ("Cogentrix") and Vistra Corp. (Dynegy) petitioned the DC Circuit Court of Appeals for review of the FERC's *CIP IROL Orders*.[80] Reporting on this matter will move to Section XV. If you have any questions concerning this proceeding, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

V. Financial Assurance/Billing Policy Amendments

- **FAP Enhancements and Clean-Up Changes (ER20-2145)**

On September 2, 2020, the FERC accepted enhancements and clean-up changes to the Financial Assurance Policy ("FAP") jointly filed by ISO-NE and the NEPOOL on June 24, 2020.[81] Among other things, those changes included: (i) updates and enhancements to the credit insurance provisions; (ii) updates to the form letter of credit and related provisions; and (iii) miscellaneous revisions, including a change to the retention period for financial assurance after membership termination and a conforming change in the FCM Charge Rate calculation (collectively, the "FAP Changes"). The changes were accepted effective as of September 10, 2020, as requested. Unless the September 2 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Paul Belval (pnbelval@daypitney.com; 860-275-0381).

VI. Schedule 20/21/22/23 Changes

- **Schedule 20A-VP: Renaming/Clean-Up (ER20-2783)**

On October 29, 2020, the FERC accepted an amended version of Schedule 20A-VP reflecting the renaming of Emera Maine as Versant Power and correcting certain typographical errors.[82] The filing was accepted effective as of November 1, 2020, as requested. Unless the October 29 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-VP: 2019 Annual Update Settlement Agreement (ER15-1434-004)**

On March 19, 2020, Emera Maine submitted a joint offer of settlement between itself and the MPUC to resolve all issues raised by the MPUC in response to Emera Maine's 2019 annual charges update filed, as previously reported, on June 10, 2019 (the "Emera 2019 Annual Update Settlement Agreement"). Under Part V of Attachment P, "Interested Parties shall have the opportunity to conduct discovery seeking any information relevant to implementation of the [Attachment P] Rate Formula. . . ." and follow a dispute resolution procedure set forth there. In accordance with those provisions, the MPUC identified certain disputes with the 2019 Annual Update, all of which are resolved by the Emera 2019 Annual Update Settlement Agreement. Comments on the Emera 2019 Annual Update Settlement Agreement were due on or before April 9, 2020; none were filed. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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[80] *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*").

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

[82] *ISO New England Inc. and Versant Power*, Docket No. ER20-2783 (Oct. 29, 2020) (unpublished letter order).

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

The MPS Merger Cost Recovery Settlement, filed by Emera Maine on May 8, 2018 to resolve all issues pending before the FERC in the consolidated proceedings set for hearing in the *MPS Merger-Related Costs Order,*[83] and certified by Settlement Judge Dring[84] to the Commission,[85] remains pending before the FERC. As previously reported, under the Settlement, permitted cost recovery over a period from June 1, 2018 to May 31, 2021 will be $390,000 under Attachment P of the BHD OATT and $260,000 under the MPD OATT. If you have any questions concerning these matters, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

- ***Opinion 531-A* Local Refund Report: FG&E (EL11-66)**

FG&E's June 29, 2015 refund report for its customers taking local service during *Opinion 531-A's* refund period remains pending. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

The TOs' November 2, 2015 refund report documenting resettlements of regional transmission charges by ISO-NE in compliance with *Opinions No. 531-A*[86] *and 531-B*[87] 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
- National Grid
- NHT
- United Illuminating
- VTransco

[83] *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.

[84] 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.

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

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

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

♦ Eversource ♦ NSTAR

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

- **Capital Projects Report - 2020 Q3 (ER21-108)**

On October 15, 2020, ISO-NE filed its Capital Projects Report and Unamortized Cost Schedule covering the third quarter ("Q3") of calendar year 2020 (the "Report"). ISO-NE is required to file the Report under Section 205 of the FPA pursuant to Section IV.B.6.2 of the Tariff. Report highlights include the following new projects: (i) nGEM Market Clearing Engine Implementation ($13,900,500); and (ii) CELT Report Automation Phase I ($155,500) The following three projects had significant changes: (i) ESI (2020 Budget decrease of $1 million); (ii) 2020 Issue Resolution Project Part II (2020 Budget decrease of $540,000); (iii) Energy Management Platform 3.2 Upgrade Part II (2020 Budget increase of $250,000); and (iv) Enterprise Application Integration Replacement Phase I (2020 Budget increase of $100,000). Comments on this filing are due on or before November 5. Thus far, NEPOOL filed comments on October 30 supporting the filing and National Grid submitted a doc-less intervention. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **Capital Projects Report - 2020 Q2 (ER20-2640)**

On October 2, 2020, the FERC accepted ISO-NE's Capital Projects Report and Unamortized Cost Schedule covering the second quarter of calendar year 2020 (the "Report").[88] Report highlights included the following new projects: (i) Forward Capacity Tracking System Infrastructure Conversion Part II ($1.7 million); (ii) Data Governance, Risk Management & Compliance ("GRC") Software Phase I ($1.1 million); 2020 Corrective Action Preventative Actions ("CAPA") ($873,300); (iv) Markets Database Enhancements ($420,000); and Gateway Data Management Application Conversion ($365,000). Projects with a significant changes were (i) nGEM Software Development Part II ($1.36 budget decrease for 2020; reallocated to 2021); (ii) Identity and Access Management Phase II (budget decrease of $1.1 million; $715,000 reallocated to 2021); (iii) TranSMART Technical Architecture Update ($399,200 budget decrease for 2020; reallocated to 2021); (iv) IMM Data Analysis Phase II (budget decrease of $250,000); (v) Sub-accounts for FTR Market (budget decrease of $191,200; reallocated to 2021); (vi) Enterprise Application Integration Replacement Phase II (budget decrease of $153,600); (vii) CIMNET Simultaneous Feasibility Test with Data Transfer Enhancements (budget increase of $361,000). Unless the October 2 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **LFTR Implementation: 48th Quarterly Status Report (ER07-476; RM06-08)**

ISO-NE filed the 48th of its quarterly status reports regarding LFTR implementation on October 15, 2020. ISO-NE reported that it implemented monthly reconfiguration auctions (accepted in ER12-2122) beginning with the month of October 2019. ISO-NE further reported that, while it will continue to evaluate its as-filed LFTR design and financial assurance issues, including an ongoing evaluation of the FTR market and risk associated with FTRs and LFTRs, it is currently focused on higher priority market-design initiatives. These status reports are not noticed for public comment.

- **Reserve Market Compliance (29th) Semi-Annual Report (ER06-613)**

As directed by the original ASM II Order,[89] as modified,[90] ISO-NE submitted its 29th semi-annual reserve market compliance report on October 1, 2020. In the 29th report, ISO-NE explained that it is focused on efforts to address energy security, and is engaged in regional discussions with stakeholders to evaluate wholesale market responses to the region's focus on rapid decarbonization. ISO-NE committed to address in

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[88] *ISO New England Inc.*, Docket No. ER20-2640 (Oct. 2, 2020) (unpublished letter order).

[89] *See NEPOOL and ISO New England Inc.*, 115 FERC ¶ 61,175 (2006) ("*ASM II Order*") (directing the ISO to provide updates on the implementation of a forward TMSR market), *reh'g denied* 117 FERC ¶ 61,106 (2006).

[90] *See NEPOOL and ISO New England Inc.*, 123 FERC ¶ 61,298 (2008) (continuing the semi-annual reporting requirement with respect to the consideration and implementation of a forward market for Ten-Minute Spinning Reserve ("TMSR")).

future reports how the objectives of a forward TMSR market might be achieved or impacted by those efforts. The October 1 report was not noticed for public comment. If there are questions on this matter, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com).

IX. Membership Filings

- **November 2020 Membership Filing (ER21-260)**

On October 30, 2020, NEPOOL requested that the FERC accept the membership of Nautilus Solar Energy, LLC (AR Sector, RG Sub-Sector, Large AR RG Group Seat). Comments on this filing are due on or before November 20, 2020.

- **October 2020 Membership Filing (ER20-3031)**

On September 30, 2020, NEPOOL requested that the FERC accept the membership of David Energy Supply, LLC (Supplier Sector). Comments on this filing were due on or before October 21; none were filed. This matter is pending before the FERC.

- **September 2020 Membership Filing (ER20-2772)**

On October 13, 2020, the FERC accepted (i) the memberships of: Acadia Renewable Energy, L.L.C. [Related Person to Nautilus Power (Generation Sector)], Sky View Ventures LLC (AR Sector, DG Sub-Sector Small Group Seat) and SYSO LLC (AR Sector, DG Sub-Sector Small Group Seat); and (ii) the name change of ENGIE Power & Gas LLC (f/k/a Plymouth Rock Energy, LLC).[91] Unless the October 13 order is challenged, this proceeding will be concluded.

- **Invenia Additional Conditions Informational Filing (ER20-2001)**

On June 5, 2020, pursuant to Section II.A.1(b) of the FAP, ISO-NE submitted an informational filing identifying the additional condition (supplemental financial assurance) required of Invenia for participation in the New England Markets. The additional condition was supported, and made a condition of Invenia's membership, by the Participants Committee at its June 4 meeting. A doc-less intervention was submitted by Public Citizen. This informational filing is pending before the FERC.

- **Suspension Notices (not docketed)**

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

Date of Suspension/ FERC Notice	***Participant Name***	***Default Type***	***Date Reinstated***
Sep 30/Oct 2	Curio Analytics, Inc. (FTR-Only)	Financial Assurance	Oct 9, 2020
Oct 15/19	Manchester Methane, LLC	Financial Assurance	Nov 2, 2020
Oct 16/20	NS Power Energy Marketing	Financial Assurance	Oct 20, 2020

Suspension notices are for the FERC's information only and are not docketed or noticed for public comment.

[91] *New England Power Pool Participants Comm.*, Docket No. ER20-2772 (Oct. 13, 2020) (unpublished letter order).

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).

- **CYPRES Report (not docketed)**

On September 14, 2020, FERC and NERC Staff published a report on cyber planning for response and recovery that outlines best practices for the electric utility industry ("CYPRES Report"). The joint staffs of FERC and NERC, and the NERC Regional Entities, developed the report after interviewing subject matter experts from eight electric utilities of varying size and function. The report includes the joint staffs' observations on their defensive capabilities and on the effectiveness of their Incident Response and Recovery ("IRR") plans. The report identifies common elements and best practices among the IRR plans. The report concludes that effective IRR plans are important resources for addressing cyber threats, and that effective IRR plans should be in place and response teams should be prepared to detect, contain, and, when appropriate, eradicate cyber threats before they can harm utility operations.

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

On September 23, 2020, following review of the comments submitted on their First White Paper,[92] FERC and NERC staff ("Joint Staffs") issued their second White Paper on Notices of Penalty Pertaining to Violations of Cortical Infrastructure Protection ("CIP") Reliability Standards ("Second White Paper"). Having determined based on those comments that the First White Paper proposal was insufficient to protect the security of the BPS, Joint Staffs modified the prior proposal. Going forward, CIP noncompliance submissions[93] will be filed or submitted by NERC with a request that the *entire* filing or submittal be designated as Critical Energy/Electric Infrastructure Information ("CEII") and FERC staff will designate the entire filing or submittal accordingly. Because of the risk associated with the disclosure of CIP noncompliance information, NERC will no longer publicly post redacted versions of CIP noncompliance filings and submittals.

- **Revised Reliability Standards: FAC-002-3; IRO-010-3; MOD-031-3; MOD-033-2; NUC-001-4; PRC-006-4; TOP-003-4 (RD20-4)**

On October 30, 2020, the FERC accepted changes to the following Reliability Standards: FAC-002-3 (Facility Interconnection Studies); IRO-010-3 (Reliability Coordinator Data Specification and Collection); MOD-031-3 (Demand and Energy Data); MOD-033-2 (Steady-State and Dynamic System Model Validation); NUC-001-4 (Nuclear Plant Interface Coordination); PRC-006-4 (Automatic Underfrequency Load Shedding); and TOP-003-4 (Operational Reliability Data) ("Revised Standards").[94] As previously reported, the changes remove references to Load Serving Entity (which is no longer an applicable entity), add Underfrequency Load Shedding ("UFLS")-Only

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

Few commenters supported the First Joint White Paper proposal without seeking modifications to either expand or reduce the amount of information that would be publicly disclosed. Comments submitted by private citizens, state representatives, and consumer advocate offices supported more disclosure of CIP noncompliance information. By contrast, most industry commenters and trade organizations raised concerns with at least some of the proposed disclosures because of the increased risk to the security of the Bulk-Power System ("BPS").

[93] Non-compliance submissions include Notices of Penalty ("NOPs"), Spreadsheet NOPs ("SNOPs"), Find, Fix and Track submissions ("FFTs") and Compliance Exceptions ("CEs")).

[94] *N. Amer. Elec. Rel. Corp.*, Docket No. RD20-4 (Oct. 30, 2020) (unpublished letter order).

Distribution Provider to PRC-006-3 as an applicable entity, and make consistent across the Standards the use of the term "Planning Coordinator". The Revised Standards will become effective (and the currently effective versions be retired) on April 1, 2021 (the first day of the first calendar quarter that is three months following FERC approval). Unless the October 30 order is challenged, this proceeding will be concluded.

- **CIP Standards Development: Informational Filings on Virtualization and Cloud Computing Services Projects (RD20-2)**

On March 19, 2020, NERC submitted, as directed by the FERC,[95] an informational filing describing the activity of two NERC CIP standard drafting projects pertaining to virtualization and cloud computing services, including a schedule for Project 2016-02 (Modifications to CIP Standards) and Project 2019-02 (BES Cyber System Information Access Management) (collectively, the "NERC Projects"). Comments were submitted by a private citizen (Barry Jones) and VMware, Inc. on April 21 and 27, 2020, respectively.

In addition, NERC is required to file on an information basis quarterly status updates, until such time as new or modified Reliability Standards are filed with the FERC. NERC filed its third informational filing on September 17, 2020, reporting a three-month deferral for each Project underway. With respect to Project 2016-02, NERC reported that "the standard drafting team anticipates filing the proposed Reliability Standards with the Commission in March 2022 (deferred from the original target date of December 2021)." With respect to Project 2019-02, NERC reported that "the standard drafting team anticipates filing the proposed Reliability Standards with the Commission in March 2021 (deferred from the December 2020 target date provided in the June Informational Filing)."

- **Revised Reliability Standard: CIP-002-6 (RM20-17)**

On June 12, 2020, NERC filed for approval a revised Reliability Standard -- CIP-002-6 (Cyber Security – BES Cyber System Categorization), and associated implementation plan, VRFs and VSLs (together, the "CIP-002 Changes"). NERC stated that the CIP-002 Changes improve upon the currently effective standard by clarifying the criterion for Transmission Owner Control Centers and tailoring the language to better reflect the risk posed by these Control Centers if unavailable or compromised. As of the date of this Report, the FERC has still not noticed a proposed rulemaking proceeding or otherwise invited public comment.

- **NOI: Enhancements to CIP Standards (RM20-12)**

On June 18, 2020, the FERC issued a notice of inquiry ("NOI") seeking comments on certain potential enhancements to the currently-effective CIP Reliability Standards. In particular, the FERC asked for comments on whether the CIP Standards adequately address: (i) cybersecurity risks pertaining to data security, (ii) detection of anomalies and events, and (iii) mitigation of cybersecurity events. In addition, the FERC asked for comments on the potential risk of a coordinated cyberattack on geographically distributed targets and whether FERC action including potential modifications to the CIP Standards would be appropriate to address such risk.

Comments were filed by NERC, the ISO/RTO Council ("IRC"), APPA/LPPC, Canadian Electricity Assoc. ("CEA"), Cogentrix, EEI/EPSA, Forescout Technologies, MISO TOs, NJ BPU, NRECA, Reliable Energy Analytics, Southwestern Power Administration, Solar Energy Industries Association ("SEIA"), Siemen's Energy, Southern Companies, TAPS, U.S. Bureau of Reclamation, U.S Corp of Army Engineers, Western Area Power Administration ("WAPA"), Wolverine Power Supply Cooperative, XTec, and J. Applebaum, J. Christopher/T. Conway, and J. 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

[95] *N. Am. Elec. Rel. Corp.*, 170 FERC ¶ 61,109 (Feb. 20, 2020).

or cloud computing services.[96] On March 25, 2020, Joint Associations[97] 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. This matter is pending before the FERC.

- ***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,[98] 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."[99] The FERC also approved the associated violation risk factors, violation severity levels, implementation plan, and effective dates proposed by NERC. Because it was not persuaded by NERC's justification for the retirement of FAC-008-4 requirement R8, the FERC remanded the retirement of requirements R7 and R8 to NERC for further consideration.[100]

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*[101] (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 pending in the *NAESB WEQ v. 003.3 Standards NOPR* (*see* Section XII below).[102]

- **Amended and Restated NERC Bylaws (RR21-1)**

On October 14, 2020, NERC petitioned the FERC for approval of its amended and restated Bylaws. NERC stated that the amendments (i) address governance matters relating to the composition of NERC's membership

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

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

[98] *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).

[99] *Order 873* at P 2.

[100] *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.

[101] *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.

[102] *Standards for Business Practices and Communication Protocols for Public Utilities*, 85 Fed. Reg. 55201 (September 4, 2020).

Sectors, certain rules relating to the Member Representatives Committee, as well as the qualification of independent trustees for the Board; (ii) update certain provisions to conform with applicable state law; and (iii) improve internal consistency and introduce ministerial changes within the Bylaws with respect to capitalizing defined terms consistently and removing inoperative provisions. Comments, if any, on the Amended and Restated Bylaws are due on or before November 4, 2020.

- **2021 NERC/NPCC Business Plans and Budgets (RR20-6)**

On November 2, 2020, the FERC accepted NERC's proposed 2021 Business Plan and Budget, as well as the 2021 Business Plans and Budgets for NERC's Regional Entities, including NPCC.[103] The FERC also granted an exception to NERC's Rules of Procedure to permit certain of the Regional Entities, including NPCC, to deposit penalty monies into their assessment stabilization reserves.[104] As previously reported, NERC's 2021 funding requirement represents an overall decrease of approximately 1.0% over its 2020 funding requirement, and the NPCC U.S. allocation of NERC's net funding requirement is $4.44 million. Unless the November 2 order is challenged, this proceeding will be concluded.

- **Report of Comparisons of Budgeted to Actual Costs for 2019 for NERC and the Regional Entities (RR20-3)**

Still pending before the FERC is the comparisons of actual to budgeted costs for 2019 for NERC and the seven Regional Entities operating in 2019, including NPCC, filed by NERC on May 29, 2020. The Report includes comparisons of actual funding received and costs incurred, with explanations of significant actual cost-to-budget variances, audited financial statements, and tables showing metrics concerning NERC and Regional Entity administrative costs in their 2019 budgets and actual results. Comments on this filing were due on or before June 19, 2020; none were filed. On July 21, 2020, NERC supplemented its May 29, 2020 filing to include the final, audited 2019 financial report for Texas Reliability Entity, Inc. ("Texas RE") (not available to be included at the time of the May 29 filing). As noted, this matter remains pending before the FERC.

XI. Misc. - of Regional Interest

- **203 Application: CPV Towantic (EC21-16)**

On October 29, 2020, CPV Towantic, LLC ("CPV Towantic"), among others, requested authorization for a transaction whereby CPV Group LP will indirectly acquire all of the indirect voting securities owned by GIP II CPV Intermediate Holdings Partnership, L.P., ("GIP II CPV"). Upon consummation, Clearway Power Marketing and GenConn Energy will no longer be CPV Related Persons. A FERC order approving the transaction on or before December 28, 2020 was requested. Comments on this application are due on or before November 19, 2020.

- **203 Application: Millennium Power Partners (EC20-103)**

On September 18, 2020, Millennium Power Partners, L.P. ("Millennium") and New Athens Generating Company, LLC (which owns facilities in New York) requested authorization for a transaction whereby Beal Bank USA, Beal Bank, SSB or their designee(s) ("Beal Bank") will acquire all of their membership interests from Talen. A FERC order approving the transaction on or before November 17, 2020 was requested. Comments on this application were due on or before October 9, 2020; none were filed. Public Citizen filed a doc-less intervention. This matter is pending before the FERC.

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

On March 13, 2020, the FERC authorized CMP to transfer to NECEC Transmission LLC 7 TSAs, executed on June 13, 2018, that provide the rates, terms, and conditions under which transmission service will be provided over the New England Clean Energy Connect ("NECEC") Transmission Line to the participants that are funding

[103] *N. Amer. Elec. Rel. Corp.*, 173 FERC ¶ 61,120 (Nov 2, 2020).

[104] *Id.* at PP 16-17; Ordering Paragraph (C).

construction of the Line.[105] Pursuant to the March 13 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.

- **VTransco Rate Schedule 2 Cancellation (ER21-256)**

On October 29, 2020, Vermont Transco filed a notice of cancellation of the Vermont Yankee Transmission Agreement, which is no longer in use. A December 28, 2020 effective date was requested. Comments on the notice of cancellation are due on or before November 19, 2020. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement: NSTAR/Ocean State Power (ER21-192)**

On October 23, 2020, NSTAR filed a Preliminary Agreement for Design, Engineering and Construction services (the "D&E Agreement") between itself and Ocean State Power. The D&E Agreement sets forth the terms and conditions under which NSTAR will undertake preliminary design and engineering activities to increase the real power capacity of Ocean State Power's large generating facility. NSTAR requested that the D&E Agreement be accepted for filing as of the date of filing, or October 23, 2020. Comments on this filing are due on or before November 13, 2020. 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).

- **NECEC TSAs: NECEC Transmission Notices of Succession and CMP Notice of Cancellation (ER21-12 et al.)**

On October 2, 2020, NECEC and CMP filed concurrently notices addressing the transfer of the 7 transmission service agreements ("TSAs") with the participants that will fund the construction, operation and maintenance of the NECEC Transmission Line. Once the transfer of the TSAs from CMP to NECEC Transmission is consummated (*see* EC20-24 above), NECEC will succeed to CMP's position in the TSAs and CMP will no longer be a party to the TSAs. As a result, NECEC filed notices of succession to the TSAs[106] and CMP filed a notice cancelling the TSAs as CMP Rate Schedules in the FERC's eTariff database. The notices are to be effective as of the date the transaction is consummated. Comments on the notices were due on or before October 23, 2020; none were filed. Like the notice that must be filed in EC20-24, NECEC and CMP committed to file notices of the effective date of the notices filed in these proceedings. These matters are pending before the FERC. If you have any questions concerning these matters, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement: CL&P/UConn (ER20-2927)**

On October 26, 2020, the FERC accepted a Preliminary Agreement for Design, Engineering and Construction services (the "D&E Agreement") between CL&P and The University of Connecticut ("UConn").[107] The D&E Agreement sets forth the terms and conditions under which CL&P will undertake preliminary design and engineering activities to increase the real power capacity of the transmission interconnection service to UConn's large generating facility. The D&E Agreement was accepted for filing as of September 21, 2020, as requested. Unless the October 26, 2020 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement Cancellation: NSTAR/Vineyard Wind (ER20-2915)**

On September 18, 2020, NSTAR filed a notice of cancellation of the Design and Engineering Agreement ("D&E Agreement") with Vineyard Wind. The D&E Agreement set forth the terms and conditions under which CL&P undertook preliminary engineering and design activities for the Vineyard Wind interconnection facilities prior to execution of the LGIA. The D&E Agreement terminated by its terms as of the effective date of the

[105] *Central Maine Power Co.*, 170 FERC 62,145 (Mar. 13, 2020).

[106] The NECEC Transmission succession notices to the 7 TSAs were separately docketed as follows: Eversource (ER21-12); National Grid (ER20-13); Unitil (ER21-14); HQ US/Eversource (ER21-15); HQ US/National Grid (ER21-17); HQ US/Unitil (ER21-18); and HQ US Additional (ER21-19).

[107] *The Conn. Light & Power Co.*, Docket No. ER20-2927 (Oct. 26, 2020) (unpublished letter order).

LGIA. A July 10, 2020 effective date to coincide with the effective date of the LGIA was requested. Comments on this filing were due on or before October 9; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **LGIA Cancellations: Superseded Great River Hydro LGIAs (Moore, Vernon, Comerford) (ER20-2897 et al.)**

Since the last Report, the FERC accepted notices of cancellation of LGIAs between New England Power Company ("NEP") and Great River Hydro (f/k/a TransCanada Hydro Northeast) governing the interconnection of the following three hydroelectric facilities: (i) Moore (ER20-2897);[108] (ii) Vernon (ER20-2896);[109] and (iii) Comerford (ER20-2815).[110] As previously reported, NEP, ISO-NE and Great River Hydro entered into a fully conforming, standard LGIAs superseding the LGIAs to be cancelled. The cancellation notices were accepted for filing as of the effective date of the superseding LGIAs (Moore – December 10, 2018; Vernon – May 8, 2019; and Comerford - August 7, 2020). Unless the orders accepting the notices are challenged, these proceedings will be concluded. If you have any questions concerning these matters, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Use Rights Transfer Agreement: NSTAR/HQ US (MMWEC) (ER20-2776)**

On October 9, 2020, the FERC accepted the agreement by which NSTAR will transfer MMWEC's use rights over the Phase I/II HVDC facilities to HQ US (MMWEC itself does not have a mechanism to effectuate the transfer) for the November 1, 2020 through October 31, 2025 period.[111] The Transfer Agreement was accepted effective as of October 31, 2020, as requested. Unless the October 9 order is challenged, this proceeding will be concluded. If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Use Rights Transfer Agreement: NSTAR/HQ US (CMEEC) (ER20-2774)**

On October 9, the FERC accepted an Agreement that transfers CMEEC's Use Rights on the Phase I/II HVDC Transmission Facilities, ultimately, to HQ US, for the November 1, 2020 through October 31, 2025 period ("Transfer Agreement").[112] Because CMEEC, as a non-jurisdictional entity, does not have a mechanism to directly transfer its Use Rights to HQ US, CMEEC is transferring its Use Rights to NSTAR who, in turn, as a Schedule 20A Service Provider under the ISO-NE OATT, is transferring those Use Rights to HQ US. CMEEC's IRH management committee voting rights, financial obligations and all other rights and responsibilities provided for in the Support Agreements and the Restated Use Agreement that are not directly related to the Use Rights and the exercise thereof by HQ US are not being transferred to HQ US. The Transfer Agreement was accepted for filing effective as of October 31, 2020, as requested. Unless the October 9 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Use Rights Transfer Agreement: NSTAR/HQ US (ENE) (ER20-2773)**

On October 9, the FERC accepted the agreement by which NSTAR will transfer ENE's use rights over the Phase I/II HVDC facilities to HQ US (ENE itself does not have a mechanism to effectuate the transfer) for the period commencing November 1, 2020 through December 31, 2023.[113] The Agreement was accepted effective September 26, 2020, as requested. Unless the October 9 order is challenged, this proceeding will be

[108] *New England Power Co.*, Docket No. ER20-2897 (Oct. 29, 2020) (unpublished letter order).

[109] *New England Power Co.*, Docket No. ER20-2896 (Oct. 29, 2020) (unpublished letter order).

[110] *New England Power Co.*, Docket No. ER20-2815 (Oct. 30, 2020) (unpublished letter order).

[111] *NSTAR Electric Co.*, Docket No. ER20-2776 (Oct. 9, 2020) (unpublished letter order).

[112] *NSTAR Electric Co.*, Docket No. ER20-2774 (Oct. 9, 2020) (unpublished letter order).

[113] *NSTAR Electric Co.*, Docket No. ER20-2773 (Oct. 9, 2020) (unpublished letter order).

concluded. If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Use Rights Transfer Agreement: NSTAR/HQ US (ER20-2724)**

On October 9, 2020, the FERC accepted an Agreement between NSTAR and H.Q. Energy Services (U.S.), Inc. ("HQ US") for the continued reassignment (through May 31, 2021) of NSTAR's Use Rights on the Phase I/II HVDC Transmission Facilities ("Transfer Agreement") to HQ US.[114] The Agreement was accepted effective November 1, 2020, as requested. Unless the October 9 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **TSAs: Second Amendments to New England Clean Energy Connect TSAs (ER20-2674 et al.)**

On October 9, 2020, the FERC accepted executed second amendments to 7 cost-based transmission service agreements ("TSAs") between CMP and the participants that will fund the construction, operation and maintenance of CMP's portion of a the NECEC Transmission Line.[115] As previously reported, the amendments are intended to implement conforming changes to some provisions of the TSAs in anticipation of, and to acknowledge, the assignment of the TSAs from CMP to NECEC Transmission LLC. The amendments were accepted, effective as of October 14, 2020, as requested. Unless the October 9 orders are challenged, these proceedings will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **VTransco Rate Schedule Cancellations (ER20-2507)**

On October 2, 2020, the FERC accepted a notice of cancellation of two agreements,[116] both entered into in 2006, among Vermont Electric Power Company, Inc. ("VELCO"), Central Vermont Public Service Corporation ("CVPS"), Green Mountain Power Corporation ("GMP"), and VTransco, which are no longer in use.[117] The notice of cancellation was accepted for filing as of July 30, 2020. Unless the October 2 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **VTransco VTA Waiver Request Clarification (ER20-1823-001)**

On October 20, 2020, the FERC granted the clarification requested by VTransco, namely that the waiver previously granted[118] should be viewed as a request to defer and amortize *up to* $10 million of the difference between the budgeted and actual ISO-NE RNS revenues over a 24-month period, beginning Jan 1, 2021.[119] Unless the October 20 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).

- **Phase II VT DMNRC Support Agreement Order 864-Related Filing (ER20-1480)**

On October 23, 2020, the FERC accepted VELCO's filing, as an agent of the Joint Owners, that described why no changes were required to the Phase II Vermont Dedicated Metallic Neutral Return

[114] *NSTAR Electric Co.*, Docket No. ER20-2724 (Oct. 9, 2020) (unpublished letter order).

[115] *Central Maine Power Co.*, Docket Nos. ER20-2674; ER20-2675; ER20-2676; ER20-2677; ER20-2678; ER20-2679; ER20-2680 (Oct. 9, 2020) (unpublished letter order). The second amendments to the 7 TSAs were separately docketed as follows: Eversource (ER20-2674); National Grid (ER20-2675); Unitil (ER20-2676); HQ US/Eversource (ER20-2677); HQ US/National Grid (ER20-2678); HQ US/Unitil (ER20-2679); and HQ US Additional (ER20-2680).

[116] The Agreements are an Amended and Restated Three Party Transmission Agreement and an Amended and Restated Three Party Agreement.

[117] *Vermont Transco LLC*, Docket No. ER20-2507 (Oct. 2, 2020) (unpublished letter order).

[118] *Vermont Transco LLC*, Docket No. ER20-1823 (May 22, 2020) (unpublished letter order).

[119] *Vermont Transco LLC*, 173 FERC ¶ 61,079 (Oct. 20, 2020).

Conductor ("DMNRC") Support Agreement[120] as a result of *Order 864*.[121] VELCO's filing was accepted effective January 27, 2020, as requested. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

In accordance with *Order 864*[122] and *Order 864-A,*[123] 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
Oct 30, 2020	ER21-311	Green Mountain Power	pending
Aug 5, 2020	ER20-2614	New England Power Support Agreement	pending
Aug 5, 2020	ER20-2610	CL&P	pending
Aug 5, 2020	ER20-2609	NSTAR	pending
Aug 5, 2020	ER20-2608	PSNH	pending
Aug 4, 2020	ER20-2607	NEP – Seabrook Transmission Support Agreement	pending
Jul 31, 2020	ER20-2594	VTransco	pending
Jul 30, 2020	ER20-2551	New England Power	pending
Jul 30, 2020	ER20-2553	NEP – LSA with MECO/Nantucket	pending
Jul 30, 2020	ER20-2572	New England TOs	pending
Jul 15, 2020	ER20-2429	CMP	pending
Jun 29, 2020	ER20-2219	New England Power	pending
Jun 23, 2020	ER20-2133	Versant Power	pending
May 18, 2020	ER20-1839	VETCO	Pending
Feb 26, 2020	ER20-1089	New England Elec. Trans. Corp.	pending
Feb 26, 2020	ER20-1088	New England Hydro Trans. Elec. Co.	pending
Feb 26, 2020	ER20-1087	New England Hydro Trans. Corp.	pending

- **FERC Enforcement Action: High Desert (IN20-6)**

On October 23, the FERC approved a Stipulation and Consent Agreement with High Desert Power Project, LLC and Middle River Power LLC (collectively "High Desert")[124] that resolved OE's investigation into whether High Desert violated FERC rules, including the Anti-Manipulation Rule, related to High Desert's receipt of Residual Unit Commitment ("RUC") awards and corresponding Bid Cost Recovery ("BCR") payments in the California Independent System Operator ("CAISO") market. OE determined that High Desert, through its

[120] The DMNRC was installed on VETCO's Phase I facilities to provide a neutral return for Phase I and Phase II at a total construction cost of approximately $2.6 million. Pursuant to the Agreement, the Joint Owners recover their total cost of service by making the DMNRC available to NHH who in turn makes the DMNRC available to the Participants pursuant to, and for the term of, the Phase II New Hampshire Transmission Facilities Support Agreement.

[121] *Vermont Elec. Power Co., Inc.*, Docket No. ER20-1480 (Oct. 23, 2020) (unpublished letter order).

[122] *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.

[123] *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*").

[124] *High Desert Power Project, LLC and Middle River Power LLC*, 173 FERC ¶ 61,087 (Oct. 23, 2020).

Scheduling Coordinator EDF Trading North America, LLC ("EDF"), "knew or should have known that High Desert's potential BCR payments were based upon RUC awards that CAISO was awarding by mistake – due to a software issue and that, despite those circumstances, rather than continue to submit RUC offers based upon supply and demand fundamentals, High Desert submitted RUC offers in a manner that sought to maximize any BCR that might be awarded in violation of the FERC's Anti-Manipulation Rule." Under the Settlement, in which High Desert neither admits nor denies the alleged violations, High Desert must ***disgorge $176,000*** plus interest to CAISO, to be allocated by CAISO in its discretion for the benefit of CAISO customers and upon approval by OE's of CAISO's plan for doing so, and ***pay a $390,000 civil penalty*** to the United States Treasury. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

XII. Misc. - Administrative & Rulemaking Proceedings

- **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 are posted in eLibrary.

- **Carbon Pricing in RTO/ISO Markets Tech Conf (Sep 30, 2020) (AD20-14)**

On September 30, 2020, the FERC convened a Commissioner-led technical conference to discuss considerations related to state adoption of mechanisms to price carbon dioxide emissions, commonly referred to as carbon pricing, in regions with FERC-jurisdictional organized wholesale electricity markets. The September 30 conference was a response to (i) the April 14, 2020 request by Interest Parties,[125] who asserted that a technical conference "would be helpful to the Commission and stakeholders in the electric energy industry in deciding how best to move forward at the state and regional levels on these issues and in the relevant organized markets" complementing "state, regional, and national discussions currently taking place" as well as to (ii) the more than 30 sets of comments on the request that were filed. Speaker opening remarks (including those of Gordon van Welie, Matt White, and other New England stakeholders), and comments are posted in eLibrary, as is a transcript of the conference.

Notice of Proposed Policy Statement. Following the technical conference, on October 15, the FERC issued a Notice of Proposed Policy Statement.[126] The FERC stated that the *Proposed Policy Statement* is "to clarify the Commission's jurisdiction over RTO/ISO market rules that incorporate a state-determined carbon price and to encourage RTO/ISO efforts to explore and consider the benefits of potential [FPA] section 205 filings to establish such rules." Specifically, the FERC proposed "to make it the policy of this Commission to encourage efforts by RTOs/ISOs and their stakeholders—including States, market participants, and consumers—to explore establishing wholesale market rules that incorporate state-determined carbon prices in RTO/ISO markets."[127] The FERC solicited comment on whether the following information and considerations it identified are "germane to the Commission's evaluation of a section 205 filing to determine whether an RTO/ISO's market rules that incorporate a state-determined carbon price in RTO/ISO markets are just, reasonable and not unduly discriminatory or preferential" or whether different or additional considerations may be or must be taken into account:

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[125] "Interested Parties" are AEE, the American Council on Renewable Energy, the American Wind Energy Association, Brookfield Renewable, Calpine, CPV, EPSA, the Independent Power Producers of New York ("IPPNY"), LS Power Associates ("LS Power"), the Natural Gas Supply Association ("NGSA"), NextEra, PJM Power Providers Group, R Street Institute, and Vistra Energy Corp.

[126] *Carbon Pricing in Organized Wholesale Electricity Markets*, 173 FERC ¶ 61,062 (Oct. 15, 2020) ("*Proposed Policy Statement*").

[127] *Id.* at P 15.

a. How, if at all, do the relevant market design considerations change depending on the manner in which the state or states determine the carbon price (e.g., price-based or quantity-based methods)? How will that price be updated?

b. How does the FPA section 205 proposal ensure price transparency and enhance price formation?

c. How will the carbon price or prices be reflected in LMP?

d. How will the incorporation of the state-determined carbon price into the RTO/ISO market affect dispatch? Will the state-determined carbon price affect how the RTO/ISO co-optimizes energy and ancillary services? Are any reforms to the co-optimization rules necessary in light of the state-determined carbon price?

e. Does the proposal result in economic or environmental leakage? How does the proposal address any such leakage?

Comments on the *Proposed Policy Statement* are due by November 16, 2020; reply comments, by December 1, 2020.

- **Hybrid Resources Technical Conference Tech Conf (Jul 23, 2020) (AD20-9)**

On July 23, 2020, the FERC convened a 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 have been posted to the FERC's eLibrary.

On August 10, 2020, the FERC invited interested persons to file post-technical conference comments to address issues raised during the technical conference and identified in the Supplemental Notice of Technical Conference issued July 13, 2020. Post-technical conference comments were due on or before September 24, 2020 and were filed by ISO-NE, CAISO, MISO, NYISO, Enel, American Council on Renewable Energy, AWEA, EEI, R Street institute, Savion, and SEIA. Since the last Report, EPRI and PJM filed comments. This matter is pending before the FERC.

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

Energy Trading Institute's[128] December 16, 2019 request that the FERC hold a technical conference and conduct a rulemaking to update the requirements adopted in *Order 741*[129] and Section 35.47 of the FERC's regulations addressing credit and risk management in the markets operated by RTO/ISOs remains pending. As previously reported, ETI, citing a recent filing by NYISO (which it protested),[130] and stating that several expedited initiatives related to RTO/ISO credit policies are underway, suggested that it would be helpful for the FERC to consolidate any "filings with this proceeding and hold the technical conference ETI is requesting by March 30,

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

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

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

2020 so the ISOs, RTOs and their stakeholders consider those discussions in any initiatives they have underway." ETI suggested in its request that RTO/ISO credit support requirements be standardized, and that the requested technical conference and rulemaking explore various ways to identify and mitigate counterparty risk (including know-you-customer ("KYC") tools and participant suspensions or bans) and enhance risk management infrastructure/processes within the organized markets. Doc-less interventions have been filed by, among others, PJM, the PJM IMM, SPP, CAISO, Tenaska, Avangrid, and Roscommon Analytics. On January 24, the IRC, including ISO-NE, submitted comments and proposed, as an alternative approach to the one suggested by ETI, that the FERC not commence a rulemaking or schedule a technical conference at this time and instead allow individual RTO/ISOs to address their respective credit and risk management issues, permit sufficient time for experience with the evolving rules to be gained, and then consider the best path forward to facilitate a dialogue on best practices and potential points of alignment among the RTO/ISO. ETI responded to those comments on February 10, 2020.

The FERC issued a notice of ETI's request for technical conference and petition for rulemaking on February 11, 2020, setting March 12, 2020 as the deadline for comments thereon. Comments were submitted by a number of parties, including APPA, CAISO, the Committee of Chief Risk Officers ("CCRO"), DC Energy, EEI, EPSA, Indicated PJM Transmission Owners,[131] and an independent consultant.[132] This matter remains pending before the FERC.

- **RTO/ISOs Common Performance Metrics (AD19-16)**

With Office of Management and Budget ("OMB") approval, FERC staff has reinstated and revised its information collection form, FERC-922, on the Performance Metrics for ISOs, RTOs, and Regions Outside ISOs and RTOs. FERC staff expects to collect Common Metrics information every two years. The revised data collection, after additions and deletions, consists of twenty-nine Common Metrics.[133] RTO/ISOs were encouraged to submit responsive information by October 30, 2020. ISO-NE submitted its information on October 30, 2020. The ISO-NE submittal will not be noticed for public comment.

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

On January 8, 2018, the FERC initiated a Grid Resilience in RTO/ISOs proceeding (AD18-7)[134] and terminated the DOE NOPR rulemaking proceeding (RM18-1).[135] In terminating the DOE NOPR proceeding, the

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[131] "Indicated PJM Transmission Owners" are Exelon Corp. ("Exelon"), American Electric Power Service Corp. ("AEP"), Dominion Energy Services, Inc. ("Dominion"), PPL Electric Utilities Corp. ("PPL"), the FirstEnergy Utility Companies. ("FirstEnergy"), East Kentucky Power Coop. ("EKPC"), Duke Energy Corp. ("Duke"), Duquesne Light Co. ("Duquesne"), and the PSEG Companies ("PSEG").

[132] W. Scott Miller, III, Whitehall Bay Energy Services, LLC.

[133] There are seven ***Group 1 metrics***: Reserve Margins, Average Heat Rates, Fuel Diversity, Capacity Factor by Technology Type, Energy Emergency Alerts (("EEA") Level 1 or Higher), Performance by Technology Type during EEA Level 1 or Higher, and Resource Availability (Equivalent Forced Outage Rate Demand ("EFORd")). There are 12 ***Group 2 metrics***: Number and Capacity of Reliability Must-Run Units, Reliability Must-Run Contract Usage, Demand Response Capability, Unit Hours Mitigated, Wholesale Power Costs by Charge Type, Price Cost Markup, Fuel Adjusted Wholesale Energy Price, Energy Market Price Convergence, Congestion Management, Administrative Costs, New Entrant Net Revenues, and Order No. 825 Shortage Intervals and Reserve Price Impacts; There are 10 ***Group 3 metrics***: Net Cost of New Entry ("Net CONE") Value, Resource Deliverability, New Capacity (Entry), Capacity Retirement (Exit), Forecasted Demand, Capacity Market Procurement and Prices, Capacity Obligations and Performance Assessment Events, Capacity Over-Performance, Capacity Under-Performance, and Total Capacity Bonus Payments and Penalties. The update metrics eliminate previously-collected metrics on reliability, RTO/ISO billing controls and customer satisfaction, interconnection and transmission processes, and system lambda.

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

[135] As previously reported, the FERC opened the DOE NOPR proceeding in response to a September 28, 2017 proposal by Energy Secretary Rick Perry, issued under a rarely-used authority under §403(a) of the Department of Energy ("DOE") Organization Act, that would have required RTO/ISOs to develop and implement market rules for the full recovery of costs and a fair rate of return for "eligible units" that (i) are able to provide essential energy and ancillary reliability services, (ii) have a 90-day fuel supply on site in the event of supply disruptions caused by emergencies, extreme weather, or natural or man-made disasters, (iii) are compliant with all applicable environmental regulations, and (iv) are not subject to cost-of-service rate regulation by any State or local authority. More than 450 comments were submitted in response to the DOE NOPR, raising and discussing an exceptionally broad spectrum of process, legal, and substantive arguments. A summary of those initial comments was circulated under separate cover and can be found with the posted

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

Grid Resilience Administrative Proceeding (AD18-7). AD18-7 was initiated to evaluate the resilience of the bulk power system in RTO/ISO regions. The FERC directed each RTO/ISO to submit information on certain resilience issues and concerns, and committed to use the information submitted to evaluate whether additional FERC action regarding resilience is appropriate. RTO submissions were due on or before March 9, 2018.

ISO-NE Response. In its response, ISO-NE identified fuel security[136] as the most significant resilience challenge facing the New England region. ISO-NE reported that it has established a process to discuss market-based solutions to address this risk, and indicated that it believed it will need through the second quarter of 2019 to develop a solution and test its robustness through the stakeholder process. In the meantime, ISO-NE indicated that it would continue to independently assess the level of fuel-security risk to reliable system operation and, if circumstances dictate, would take, with FERC approval when required, actions it determines to be necessary to address near-term reliability risks. ISO-NE's response was broken into three parts: (i) an introduction to fuel-security risk; (ii) background on how ISO-NE's work in transmission planning, markets, and operations support the New England bulk power system's resilience; and (iii) answers to the specific questions posed in the January 8 order.

Industry Comments. Following a 30-day extension issued on March 20, 2018, reply comments were due on or before May 9, 2018. NEPOOL's comments, which were approved at the May 4 meeting, were filed May 7, and were among over 100 sets of initial comments filed. A summary of the comments that seemed most relevant to New England and NEPOOL was circulated to the Participants Committee on May 15 and is posted on the NEPOOL website. On May 23, NEPOOL submitted a limited response to four sets of comments, opposing the suggestions made in those pleadings to the extent that the suggestions would not permit full use of the Participant Processes. Supplemental comments and answers were also filed by FirstEnergy, MISO South Regulators, NEI, and EDF. Exelon and American Petroleum Institute filed reply comments. FirstEnergy included in this proceeding its motion for emergency action also filed in ER18-1509 (ISO-NE Waiver Filing: Mystic 8 & 9), which Eversource answered (in both proceedings). Reply comments were filed by APPA and AMP and the Nuclear Energy Institute ("NEI") moved to lodge presentations by the National Infrastructure Advisory Council. On December 6, the Harvard Electricity Law Initiative filed a comment suggesting that, as a matter of law, "Commission McNamee cannot be an impartial adjudicator in these proceedings" and "any proceeding about rates for 'fuel-secure' generators" and should recuse himself. Similarly, on December 18, "Clean Energy Advocates"[137] requested Commissioner McNamee recuse himself from these proceedings. These matters remain pending before the FERC.

FirstEnergy DOE Application for Section 202(c) Order. In a related but separate matter, FirstEnergy Solutions ("FirstEnergy") asked the Department of Energy ("DOE") in late March to issue an emergency order to provide cost recovery to coal and nuclear plants in PJM, saying market conditions there are a "threat to energy security and reliability". FirstEnergy made the appeal under Section 202(c) of the FPA, which allows the DOE to

materials for the November 3, 2017 Participants Committee meeting. Reply comments and answers to those comments were filed by over 100 parties.

[136] ISO-NE defined fuel security as "the assurance that power plants will have or be able to obtain the fuel they need to run, particularly in winter – especially against the backdrop of coal, oil, and nuclear unit retirements, constrained fuel infrastructure, and the difficulty in permitting and operating dual-fuel generating capability."

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

issue emergency orders to keep plants operating, but has previously been exercised only in response to natural disasters. Action on that 2018 request is pending.

- **NOPR: Electric Transmission Incentives Policy (RM20-10)**

On March 20, 2020, the FERC issued a NOPR[138] proposing to revise its existing transmission incentives policy and corresponding regulations.[139] The proposed revisions include 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***.
- ***RTO-Participation Inventive*.** A 100-basis-point increase for transmitting utilities that turn over their wholesale facilities to an RTO, ISO, or Transmission Organization, and available regardless of whether participation 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.

A more detailed summary of the NOPR was distributed to the Transmission Committee and discussed at its March 25, 2020 meeting. Over 80 sets of comments on the proposed revisions were filed on or before the July 1, 2020[140] 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. The NOPR is now pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

[138] *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*, 170 FERC ¶ 61,204 (Mar. 20, 2020) ("*Electric Transmission Incentives NOPR*").

[139] 18 CFR 35.35 (2020).

[140] The *Electric Transmission* Incentives NOPR was published in the *Fed. Reg.* on Apr. 2, 2020 (Vol. 85, No. 64) pp. 18,784-18,810. Requests for extension of time to file comments were filed by American Manufacturers, APPA/TAPS, and State Entities; WIRES and EEI each opposed the requested extensions. No extension of time to file comments was granted.

- ***Order 2222*: DER Participation in RTO/ISO Markets (RM18-9)**

On September 17, the FERC issued a final rule ("*Order 2222*")[141] adopting reforms to remove what it found were barriers to the participation of distributed energy resource ("DER")[142] aggregations in the RTO/ISO markets. *Order 2222* requires each RTO/ISO to revise its tariff to ensure that its market rules facilitate the participation of DER aggregations. Specifically, the tariff provisions addressing distributed energy resource aggregations must:

(1) allow distributed energy resource aggregations to participate directly in RTO/ISO markets and establish distributed energy resource aggregators as a type of market participant;

(2) allow distributed energy resource aggregators to register distributed energy resource aggregations under one or more participation models that accommodate the physical and operational characteristics of the distributed energy resource aggregations;

(3) establish a minimum size requirement for distributed energy resource aggregations that does not exceed 100 kW;

(4) address locational requirements for distributed energy resource aggregations;

(5) address distribution factors and bidding parameters for distributed energy resource aggregations;

(6) address information and data requirements for distributed energy resource aggregations;

(7) address metering and telemetry requirements for distributed energy resource aggregations;

(8) address coordination between the RTO/ISO, the distributed energy resource aggregator, the distribution utility, and the relevant electric retail regulatory authorities;

(9) address modifications to the list of resources in a distributed energy resource aggregation;

(10) address market participation agreements for distributed energy resource aggregators; and

(11) Accept bids from a DER aggregator if its aggregation includes DERs that are customers of utilities that distributed more than 4 million MWh in the previous fiscal year. An RTO/ISO must not accept bids from a DER aggregator if its aggregation includes DERs that are customers of utilities that distributed 4 million MWhs or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers to be bid into RTO/ISO markets by a DER aggregator.

Each RTO/ISO must file the tariff changes needed to implement the requirements of *Order 2222* on or before July 19, 2021.[143] To the extent that an RTO/ISO proposes to comply with any or all of the requirements in *Order 2222* using its currently effective requirements for distributed energy resources, it must demonstrate on compliance that its existing approach meets *Order 2222*'s requirements.

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[141] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 172 FERC ¶ 61,247 (Sep. 17, 2020).

[142] The FERC defined a DER as "any resource located on the distribution system, any subsystem thereof or behind a customer meter. These resources may include, but are not limited to, electric storage resources, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment."

[143] *Order 2222* was published in the *Fed. Reg.* on Oct. 21, 2020 (Vol. 85, No. 204) pp. 67,094-6,158.

Requests for Rehearing. Requests for clarification and/or rehearing of *Order 2222* were filed by Excel Energy Services, the Kansas Corporation Commission, AEE and AEMA, and Public Interest Organizations.[144] Those requests for rehearing are pending, with FERC action required on or before November 16, 2020, or the requests will be deemed denied by operation of law.

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

As previously reported, *Order 860,*[145] issued three years after the FERC's *Data Collection NOPR,*[146] (i) revises the FERC's MBR regulations by establishing a relational database of ownership and affiliate information for MBR Sellers (which, among other uses, will be used to create asset appendices and indicative screens), (ii) reduces the scope of information that must be provided in MBR filings, modifies the information required in, and format of, a MBR Seller's asset appendix, (iii) changes the process and timing of the requirements to advise the FERC of changes in status and affiliate information, and (iv) eliminates the requirement adopted in *Order 816* that MBR Sellers submit corporate organization charts. In addition, the FERC stated that it will not adopt the *Data Collection NOPR* proposal to collect Connected Entity data from MBR Sellers and entities trading virtuals or holding FTRs. The FERC will post on its website high-level instructions that describe the mechanics of the relational database submission process and how to prepare filings that incorporate information that is submitted to the relational database. As recently extended (*see* below), *Order 860* will become effective April 1, 2021, and submitters will have until close of business on August 2, 2021 to make their initial baseline submissions. Submitters will be required to obtain in Spring 2021 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,[147] 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,[148] 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.

Effective Date Extended by 6 Months. On May 6, 2020, EEI requested a four-month extension of implementation of *Order 860*. EPSA supported that request on May 13, 2020. On May 20, the FERC issued a notice extending the effective and associated implementation dates of *Order 860* by *six* months. The new *Order 860* effective date will be April 1, 2021, and the deadline for baseline submissions to and including August 2, 2021. First change in status filings under these new timelines will be due August 31, 2021.

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[144] For purposes of this proceeding, "Public Interest Organizations" are Sierra Club, Sustainable FERC Project and NRDC.

[145] *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).

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

[147] 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.

[148] *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*").

- **NOPR: NAESB WEQ Standards v. 003.3 - Incorporation by Reference into FERC Regs (RM05-5-029, -030)**

On July 16, 2020, the FERC issued a NOPR proposing to incorporate by reference, with certain enumerated exceptions, the latest version (Version 003.3) of certain Standards for Business Practices and Communication Protocols for Public Utilities adopted by the NAESB Wholesale Electric Quadrant ("WEQ").[149] Despite having only recently incorporated Version 003.2 in its regulations, the FERC proposed to move forward on Version 003.3 because this Version contains a number of major initiatives whose incorporation by reference "will improve the security and the efficiency of business transactions. These include enhanced cybersecurity standards resulting from an assessment by Sandia, improved methodologies for resolving transmission loading relief, and standards for determining available transfer capacity."[150] Comments on the *NAESB WEQ v. 003.3 Standards NOPR* were due on or before November 3, 2020[151] and were filed by Bonneville Power Administration ("BPA"), EEI, the IRC, and Open Access Technology International. The *NAESB WEQ v. 003.3 Standards NOPR* is pending before the FERC.

- ***Order 676-I*: NAESB WEQ Standards v. 003.2 - Incorporation by Reference into FERC Regs (RM05-5-027)**

On February 4, 2020, the FERC issued Order *676-I*,[152] which incorporates by reference into its regulations, with certain enumerated exceptions, the latest version (Version 003.2) of certain Standards for Business Practices and Communication Protocols for Public Utilities adopted by the NAESB Wholesale Electric Quadrant.[153] The Version 003.2 Standards included NAESB's Version 003.1 revisions, which were the subject of an earlier NOPR.[154] The FERC declined to adopt the proposal to remove the incorporation by reference of the WEQ-006 Manual Time Error Correction Business Practice Standards as adopted by NAESB. *Order 676-I* will become effective April 27, 2020.[155] Requests for clarification and/or rehearing of *Order 676-I* were filed by EEI and Southern Companies. On April 6, 2020, the FERC issued a tolling order to afford it additional time to consider those requests, which remain pending before the FERC.

Compliance dates: Public utilities must make a compliance filing to comply with the requirements of *Order 676-I* through eTariff no later than July 27, 2020. The FERC will set an effective date for the proposed tariff changes in the order(s) on the compliance filings, but no earlier than October 27, 2020.

- **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.[156] 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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[149] *Standards for Business Practices and Communication Protocols for Public Utilities*, 172 FERC ¶ 61,047 (July 16, 2020) ("*NAESB WEQ v. 003.3 Standards NOPR*").

[150] The *NAESB WEQ v. 003.3 NOPR* at P .

[151] The *NAESB WEQ v. 003.3 NOPR* was published in the *Fed. Reg.* on Sep. 4, 2020 (Vol. 85, No. 173) pp. 55,201-55,219.

[152] *Standards for Business Practices and Communication Protocols for Public Utilities*, Order No. 676-I, 170 FERC ¶ 61,062 (Feb. 4, 2020) ("*Order 676-I*"), *reh'g and/or clarif. pending*.

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

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

[155] *Order 676-I* was published *Fed. Reg.* on Feb. 25, 2020 (Vol. 85, No. 37) pp. 10,571-10,586.

[156] *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[157] 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).

[157] 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,[158] 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,[159] 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,[160] KEPC, and the Sustainable FERC Project. The proposed Policy Statement is 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*.[161] 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").[162] 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.[163] 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[164] answered the New England TO's May 10 supplemental comments. On June 15, 2020, Joint Parties[165] 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.[166] WIRES submitted supplemental

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158 *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.

159 "Indicated Generators" are Vistra, NRG, FirstLight, Cogentrix, and LS Power.

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

161 *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*").

162 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.[162] 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).

163 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.

164 For this purpose, "Complainant-Aligned Parties" are: Connecticut Public Utilities Regulatory Authority, Connecticut Office of the Attorney General, Connecticut Department of Energy and Environmental Protection, Connecticut Office of Consumer Counsel, Massachusetts Office of the Attorney General, Massachusetts Department of Public Utilities, Massachusetts Municipal Wholesale Electric Company, and New Hampshire Electric Cooperative.

165 "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.

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

comments on June 18, 2020 requesting that the FERC take further action in this proceeding to "resolve the uncertainty surrounding its base ROE methodology and establish a policy consistent with the recommendations made in these comments" (recommending a framework that employs all four of the previously proposed ROE models, including the Expected Earnings model, along with certain modifications, to ensure that ROEs attract capital investment in needed transmission infrastructure). On June 24, EEI and WIRES requested the FERC issue a NOI regarding the FERC's policy for determining base ROE applicable to the electric industry as a whole. Six Cities answered Joint Parties on June 30. APPA answered EEI and WIRES' June 24 motion.

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

On April 19, 2018, the FERC announced its intention to revisit its approach under its 1999 Certificate Policy Statement to determine whether a proposed jurisdictional natural gas project is or will be required by the present or future public convenience and necessity, as that standard is established in NGA Section 7. Specifically, the NOI[167] seeks comments from interested parties on four broad issue categories: (1) project need, including whether precedent agreements are still the best demonstration of need; (2) exercise of eminent domain; (3) environmental impact evaluation (including climate change and upstream and downstream greenhouse gas emissions); and (4) the efficiency and effectiveness of the FERC certificate process. Pursuant to a May 23 order extending the comment deadline by 30 days,[168] comments were due on or before July 25, 2018. Literally thousands of individual and mass-mailed comments were filed. This matter remains pending before the FERC.

XIII. Natural Gas Proceedings

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

- **Natural Gas-Related Enforcement Actions**

The FERC continues to closely monitor and enforce compliance with regulations governing open access transportation on interstate natural gas pipelines:

BP (IN13-15). On July 11, 2016, the FERC issued *Opinion 549*[169] affirming Judge Cintron's August 13, 2015 Initial Decision finding that BP America Inc., BP Corporation North America Inc., BP America Production Company, and BP Energy Company (collectively, "BP") violated Section 1c.1 of the Commission's regulations ("Anti-Manipulation Rule") and NGA Section 4A.[170] Specifically, after extensive discovery and hearing procedures, Judge Cintron found that BP's Texas team engaged in market manipulation by changing their trading patterns, between September 18, 2008 through the end of November 2008, in order to suppress next-day natural gas prices at the Houston Ship Channel ("HSC") trading point in order to benefit correspondingly long position at the Henry Hub trading point. The FERC agreed, finding that the "record shows that BP's trading practices during the Investigative Period were fraudulent or deceptive, undertaken with the requisite scienter, and carried out in connection with Commission-jurisdictional transactions."[171] Accordingly, the FERC assessed a ***$20.16 million civil penalty*** and required BP to ***disgorge $207,169*** in "unjust profits it received as a result of its manipulation of the Houston Ship Channel Gas Daily index." The $20.16 million civil penalty was at the top of the FERC's Penalty Guidelines range, reflecting increases for having had a prior adjudication within 5 years of the violation, and for BP's violation of a

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

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

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

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

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

FERC order within 5 years of the scheme. BP's penalty was mitigated because it cooperated during the investigation, but BP received no deduction for its compliance program, or for self-reporting. The *BP Penalties Order* also denied BP's request for rehearing of the order establishing a hearing in this proceeding.[172] BP was directed to pay the civil penalty and disgorgement amount within 60 days of the *BP Penalties Order*. On August 10, 2016 BP requested rehearing of the *BP Penalties Order*. On September 8, 2018, the FERC issued a tolling order to afford it additional time to consider BP's request for rehearing of the *BP Penalties Order*, which remains pending.

On September 7, 2016, BP submitted a motion for modification of the *BP Penalties Order's* disgorgement directive because it cannot comply with the disgorgement directive as ordered. BP explained that the entity to which disgorgement was to be directed, the Texas Low Income Home Energy Assistance Program ("LIHEAP"), is not set up to receive or disburse amounts received from any person other than the Texas Legislature. In response, on September 12, 2016, the FERC stayed the disgorgement directive (until an order on BP's pending request for rehearing is issued), but indicated that interest will continue to accrue on unpaid monies during the pendency of the stay.[173]

BP moved, on December 11, 2017, to lodge, to reopen the proceeding, and to dismiss, or in the alternative, for reconsideration based on changes in the law it asserted are dispositive and that have occurred since BP filed its request for rehearing of the *BP Penalties Order*. FERC Staff asked for, and was granted, additional time, to January 25, 2018, to file its Answer to BP's December 11 motion. FERC Staff filed its answer on January 25, 2018, and revised that answer on January 31. On February 9, BP replied to FERC Staff's revised answer. This matter remains pending before the FERC.

Total Gas & Power North America, Inc. et al. (IN12-17). On April 28, 2016, the FERC issued a show cause order[174] in which it directed Total Gas & Power North America, Inc. ("TGPNA") and its West Desk traders and supervisors, Therese Tran f/k/a Nguyen ("Tran") and Aaron Hall (collectively, "Respondents") to show cause why Respondents should not be found to have violated NGA Section 4A and the FERC's Anti-Manipulation Rule through a scheme to manipulate the price of natural gas at four locations in the southwest United States between June 2009 and June 2012.[175]

The FERC also directed TGPNA to show cause why it should not be required to disgorge unjust profits of ***$9.18 million***, plus interest; TGPNA, Tran and Hall to show cause why they should not be assessed civil penalties (TGPNA - ***$213.6 million***; Hall - ***$1 million*** (jointly and severally with TGPNA); and Tran - ***$2 million*** (jointly and severally with TGPNA)). In addition, the FERC directed TGPNA's parent company, Total, S.A. ("Total"), and TGPNA's affiliate, Total Gas & Power, Ltd. ("TGPL"), to show cause why they should not be held liable for TGPNA's, Hall's, and Tran's conduct, and be held jointly and severally liable for their disgorgement and civil penalties based on Total's and TGPL's significant control and authority over TGPNA's daily operations. Respondents filed their answer on July 12, 2016. OE Staff replied to Respondents' answer on September 23, 2016. Respondents answered

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

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

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

[175] The allegations giving rise to the Total Show Cause Order were laid out in a September 21, 2015 FERC Staff Notice of Alleged Violations which summarized OE's case against the Respondents. Staff determined that the Respondents violated section 4A of the Natural Gas Act and the Commission's Anti-Manipulation Rule by devising and executing a scheme to manipulate the price of natural gas in the southwest United States between June 2009 and June 2012. Specifically, Staff alleged that the scheme involved making largely uneconomic trades for physical natural gas during bid-week designed to move indexed market prices in a way that benefited the company's related positions. Staff alleged that the West Desk implemented the bid-week scheme on at least 38 occasions during the period of interest, and that Tran and Hall each implemented the scheme and supervised and directed other traders in implementing the scheme.

OE's September 23 answer on January 17, 2017, and OE Staff responded to that answer on January 27, 2017. This matter remains pending before the FERC.

- **New England Pipeline Proceedings**
  The following New England pipeline projects are currently under construction or before the FERC:
  - ***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
    - Application for a certificate of public convenience and necessity pending.
    - Since the Last Report, the FERC issued on September 30 its Environmental Assessment Report for the ExC Project ("EA"), Iroquois responded to a October 1 data request regarding Administrative and General (A&G) Expenses, and 22 sets of comments were filed in response to the EA.

- **Non-New England Pipeline Proceedings**
  The following pipeline projects could affect ongoing pipeline proceedings in New England and elsewhere:
  - **Northern Access Project (CP15-115)**
    - The New York State Department of Environmental Conservation ("NY DEC") and the Sierra Club requested rehearing of the *Northern Access Certificate Rehearing Order* on August 14 and September 5, 2018, respectively. On August 29, National Fuel Gas Supply Corporation and Empire Pipeline ("Applicants") answered the NY DEC's August 14 rehearing request and request for stay. On April 2, 2019, the FERC denied the NY DEC and Sierra Club requests for rehearing.[176] 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*.[177] 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,[178] 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,

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

[177] *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).

[178] The DC Circuit has indicated that project applicants who believe that a state certifying agency has waived its authority under CWA section 401 to act on an application for a water quality certification must present evidence of waiver to the FERC. *Millennium Pipeline Co., L.L.C. v. Seggos*, 860 F.3d 696, 701 (D.C. Cir. 2017).

2017.[179] 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.[180] On February 2, 2019, the 2nd Circuit vacated the decision of the NY DEC and remanded the case with instructions for the NY DEC to more clearly articulate its basis for the denial and how that basis is connected to information in the existing administrative record. The matter is again before the NY DEC.
- On November 26, 2018, the Applicants filed a request at FERC for a 3-year extension of time, until February 3, 2022, to complete construction and to place the certificated facilities into service. The Applicants cited the fact that they "do not anticipate commencement of Project construction until early 2021 due to New York's continued legal actions and to time lines required for procurement of necessary pipe and compressor facility materials." The extension request was granted on January 31, 2019.
- On August 8, 2019, the NY DEC again denied Applicants request for a Water Quality Certification, and as directed by the Second Circuit,[181] 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.[182]
- Since the last Report, 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. Comments on the request are due on or before November 6, 2020. Thus far, over 30 sets of comments on the requested extension have been filed.

XIV. State Proceedings & Federal Legislative Proceedings

- **Executive Order on Securing the United States Bulk-Power System**

On May 1, 2020, President Trump signed an Executive Order that authorizes U.S. Secretary of Energy Dan Brouillette to work with the Cabinet and energy industry to secure America's BPS. The Executive Order prohibits Federal agencies and U.S. persons from "acquiring, transferring, or installing BPS equipment in which any foreign country or foreign national has any interest and the transaction poses an unacceptable risk to national security or the security and safety of American citizens. Evolving threats facing our critical infrastructure have only served to highlight the supply chain risks faced by all sectors, including energy, and the need to ensure the availability of secure components from American companies and other trusted

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[179] *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*").

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

[181] 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).

[182] *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).

sources." The Secretary of Energy is accordingly authorized to (i) establish and publish criteria for recognizing particular equipment and vendors as "pre-qualified" (pre-qualified vendor list); (ii) identify any now-prohibited equipment already in use, allowing the government to develop strategies and work with asset owners to identify, isolate, monitor, and replace this equipment as appropriate; and (iii) work closely with the Departments of Commerce, Defense, Homeland Security, Interior; the Director of National Intelligence; and other appropriate Federal agencies to carry out the authorities and responsibilities outlined in the Executive Order. A Task Force led by Secretary Brouillette will develop energy infrastructure procurement policies to ensure national security considerations are fully integrated into government energy security and cybersecurity policymaking. The Task Force will consult with the energy industry through the Electricity and Oil and Natural Gas Subsector Coordinating Councils to further its efforts on securing the BPS. A copy of the Executive Order may be accessed here.

XV. Federal Courts

The following are matters of interest, including petitions for review of FERC decisions in NEPOOL-related proceedings, that are currently pending before the federal courts (unless otherwise noted, the cases are before the U.S. Court of Appeals for the District of Columbia Circuit). An "**" following the Case No. indicates that NEPOOL has intervened or is a litigant in the appeal. The remaining matters are appeals as to which NEPOOL has no organizational interest but that may be of interest to Participants. For further information on any of these proceedings, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **ISO-NE Implementation of Order 1000 Exemptions for Immediate Need Reliability Projects (20-1422); Underlying FERC Proceeding: ER19-90[183]**
  Petitioner: LS Power

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. Appearances are due November 19, 2020. Parties must file docketing statements and statement of issues to be raised also by November 19. Dispositive motions, if any, and a Certified Index to the Record must be filed by December 4, 2020.

- **CIP IROL Cost Recovery Rules (20-1389); Underlying FERC Proceeding: ER20-739[184]**
  Petitioner: Cogentrix, Vistra

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. Appearances are due November 19, 2020. Parties must file docketing statements and statement of issues to be raised also by November 19. Dispositive motions, if any, and a Certified Index to the Record must be filed by December 4, 2020.

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[183] *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 b operation of law, modifying discussion in *Order Terminating Proceeding,* but reaching same result).

[184] *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*").

- **Mystic 8/9 Cost of Service Agreement (20-1343; 20-1361, 20-1362; 20-1365, 20-1368)(consolidated); Underlying FERC Proceeding: EL18-1639[185]**
  Petitioners: Mystic (1343), NESCOE (1361), MA AG (1362), CT Parties (1365, 1368)

Mystic, NESCOE, MA AG, and CT Parties 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.[186] The cases have been consolidated into Case No. 20-1343. Appearances were filed October 8, 2020. On October 8 (in the case of Mystic) and October 16 (in the case of the remaining Petitioners), statements of issues and docketing statements were filed. Also on October 16, the FERC filed an unopposed motion to hold this appeal in abeyance until the earlier of December 15, 2020 (60 days) or the date of the issuance by the FERC of a further order on rehearing. In addition, the FERC asked for 21 days from that day for the parties to file motions to govern further proceedings. The FERC motion is pending before the Court.

- ***CASPR* (20-1333)**
  Underlying FERC Proceeding: ER18-619[187]
  Petitioners: Sierra Club, NRDC, RENEW Northeast, and CLF

On August 31, 2020, the Sierra Club, NRDC, RENEW Northeast, and CLF petitioned the DC Circuit Court of Appeals for review of the FERC's order accepting ISO-NE's CASPR revisions (which, under *Allegheny*, is ripe for review). On October 2, 2020, appearances, docketing statements, a statement of issues to be raised, and a statement of intent to utilize deferred joint appendix were filed. On October 19, 2020, the FERC moved to dismiss the case for a lack of jurisdiction (arguing that Petitioners missed their opportunity to timely file their Petition for review in 2018, and filing within 60 days of *Allegheny* did not make their Petition timely). Alternatively, the FERC asked that the case be held in abeyance for 60 days pending issuance of a further FERC order on this matter. On October 29, Petitioners opposed the FERC's motion. The FERC's motion is pending before the Court.

- ***Opinion 531-A* Compliance Filing Undo (20-1329)**
  Underlying FERC Proceeding: ER15-414[188]
  Petitioners: TOs' (CMP et al.)

On August 28, 2020, the TOs[189] 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*[190] 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 FERC granted that motion, and directed the parties to file motions to govern future proceedings in this case by February 2, 2021.

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

[186] 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.

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

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

[189] 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.

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

- **2013/14 Winter Reliability Program Order on Compliance and Remand (20-1289, 20-1366) (consol.)**
  Underlying FERC Proceeding: ER13-2266[191]
  Petitioner: TransCanada

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*.[192] NEPGA intervened on October 15, 2020 (and its intervention granted on October 28). On October 16, TransCanada filed a docketing statement and statement of issues. On October 29, the FERC filed a certified index to the record and an unopposed motion for a 60-day briefing schedule.

- **ISO-NE's Inventoried Energy Program (Chapter 2B) Proposal (19-1224***; 19-1247; 19-1252; 19-1253)(consolidated); Underlying FERC Proceeding: ER19-1428**[193]
  Petitioners: ENECOS (Belmont et al.) (19-1224); MA AG (19-1247); NH PUC/NH OCA (19-1252); Sierra Club/UCS (19-1253)

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). With the remand proceedings concluded, Petitions filed on September 18, 2020, as directed, a motion to govern further proceedings in these consolidated cases. The proposed briefing schedule includes the following: Petitioners' Opening Briefs (December 11, 2020); Respondent Brief of FERC (February 9, 2021); Intervenors' Joint Brief in Support of Respondent (February 18, 2021); Petitioners' Reply Briefs (April 1, 2021); Deferred Appendix (April 22, 2021); and Final Briefs (May 6, 2021). Since the last Report, 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 (MA AG, NH PUC/NH OCA and Sierra Club/UCS on October 19; ENECOS, October 20). As noted, Opening Briefs are due December 11, 2020.

Other Federal Court Activity of Interest

- ***Order 872* (20-72788) (9th Cir.)**
  Underlying FERC Proceeding: RM19-15[194]
  Petitioner: SEIA

On September 17, 2020, SEIA petitioned the 9th Circuit Court of Appeals for review of *Order 872*.[195] On October 9, the FERC filed an unopposed motion for the Court to hold this appeal in abeyance, suspend filing of the certified index to the record, and issue a new briefing schedule after January 4, 2021. The abeyance will permit the FERC to address the pending rehearing requests in a future order. On October 26, 2020, the Court granted the FERC's motion, suspended briefing, and directed the FERC to file a status report, or a motion for appropriate relief

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191 171 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*").)

192 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.

193 162 FERC ¶ 61,127 (Feb. 15, 2018) ("*Order 841*"); 167 FERC ¶ 61,154 (May 16, 2019) ("*Order 841-A*").

194 *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).

195 *Order 872* approved pricing and eligibility revisions to the FERC's long-standing regulations implementing sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA"), including: state flexibility in setting QF rates; a decrease (to 5 MW) to the threshold for a rebuttable presumption of access to nondiscriminatory, competitive markets; updates to the "One-Mile Rule"; clarifications to when a QF establishes its entitlement to a purchase obligation; and provision for certification challenges.

on or before that date, with a failure to timely do so potentially resulting in the termination of the stay of proceedings.

- **Allegheny Defense Project v. FERC (17-1098)**
  Underlying FERC Proceeding: CP15-138[196]
  Petitioner: Allegheny Defense Project

On June 30, in a decision[197] that will likely have a profound effect on current and future proceedings before the FERC, the DC Circuit ruled that the Natural Gas Act ("NGA") does not allow FERC to delay appellate review of its substantive orders through its common practice of issuing tolling[198] orders. The decision at the very least modifies—if not wholly overrules—a long-unbroken line of cases that rejected as premature appeals from FERC orders while applications for rehearing were pending. While the case was decided under the NGA,[199] there is little doubt that the court's rejection of FERC's long-standing tolling policy will impact proceedings arising under the FPA as well.

Following issuance of the decision, the FERC asked the Court for a stay of issuance of the mandate in this case for 90 days (the Court had ordered that the mandate be issued on July 7, 2020). The FERC argued that the stay would permit the FERC time to assess how to implement the Court's decision and would also allow the federal government to consider whether to file a petition for writ of certiorari in the Supreme Court. Petitioners opposed the FERC's motion. On July 23, 2020, the Court issued a *per curiam* order staying issuance of the mandate through October 5, 2020, as requested by the FERC. Also of note, On July 2, 2020, Chairman Chatterjee and Commissioner Glick issued a joint statement asking Congress to consider providing FERC with additional time to act on rehearing requests. On October 6, 2020, the Mandate was issued to the FERC. Reporting on this proceeding has now concluded.

- **FERC orders on PG&E Bankruptcy (19-71615) (9th Cir.)**
  Underlying FERC Proceeding: EL19-35, EL19-36[200]
  Petitioner: PG&E

On June 26, PG&E appealed the FERC's orders finding that it has concurrent jurisdiction with the bankruptcy courts to review and address the disposition of wholesale power contracts sought to be rejected through its bankruptcy. On July 11, PG&E moved to suspend the briefing schedule pending the Court's decision on whether to authorize direct appeal of a decision by the Bankruptcy Court in the Northern District of California. In

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[196] *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).

[197] *Allegheny Def. Project v. FERC*, 964 F.3d 1, 2020 WL 3525547 (D.C. Cir. June 30, 2020).

[198] A tolling order is a brief order issued within 30 days of receiving an application for rehearing that does not address the merits of the rehearing request, but rather explicitly "grants" rehearing for the purpose of giving the agency more time to consider the arguments. FERC then treats the tolling order as indefinitely suspending the 30-day statutory deadline in order to afford more time to fully address the rehearing request. FERC has for decades routinely issued tolling orders in response to identical language in both the NGA and the FPA that requires any party seeking to challenge a FERC order on appeal to first request a rehearing before FERC, and FERC to act within 30 days after receiving any such requests. If FERC does not act within that time, the rehearing request is deemed denied and the FERC order is final and ripe for appeal.

[199] In this case, the Petitioners challenged the FERC's use of a tolling order in response to their applications for rehearing of a FERC order that issued a certificate of public convenience and necessity to the Atlantic Sunrise Project. Those rehearing applications were pending for nine months before the FERC ruled on them. When the appeals were filed, the FERC and others sought to use the pending rehearing requests as the basis for dismissing the petitions as "incurably premature." Since the applications for rehearing did not stay the FERC's issuance of the certificate, the petitioners also sought a stay from the FERC, which FERC did not act on for almost seven months. While the rehearings and requests for stay were still before the FERC, the pipeline sponsors of the Atlantic Sunrise Project proceeded to condemn land and begin construction activities. By the time the first panel of the court heard oral arguments on the petitions for review, the project had been built and in service for two months.

[200] *NextEra Energy, Inc. v. PG&E*, 166 FERC ¶ 61,049 (Jan. 25, 2019); *Exelon Corp. v. PG&E*, 166 FERC ¶ 61,053 (Jan. 28, 2019); *Order Denying Rehearing*, 167 FERC ¶ 61,096 (May 1, 2019).

a declaratory judgment, the Bankruptcy Court came to a completely different conclusion than the FERC and held that it has "original and exclusive jurisdiction over . . . [PG&E's] rights to assume or reject executory contracts under 11 U.S.C. § 365" and that the FERC "does not have concurrent jurisdiction, or any jurisdiction, over the determination of whether any rejections of power purchase contracts by [PG&E] should be authorized."[201] Because of the opposite conclusions, PG&E suggested that, should the Ninth Circuit allow the direct appeal of the Bankruptcy Court decision, the two appeals should proceed together. The PG&E motion was granted on August 1.

The Court ordered the parties to submit supplemental briefs by July 8, 2020 addressing the impact on this appeal of the confirmation of PG&E's bankruptcy plan. (PG&E has since successfully emerged from bankruptcy). While the parties agreed in their briefs that the case is moot given PG&E's voluntary assumption of its contracts in its reorganization plan, there was disagreement over whether the FERC's orders should be vacated. Hearings were held on August 14, 2020.

In an unpublished memorandum issued on October 7, 2020, the Court stated that it "need not - and cannot - reach the merits of this dispute, because the cases became moot when the bankruptcy court confirmed a reorganization plan requiring PG&E to assume, rather than reject, the contracts at issue." The Court then dismissed PG&E's petition for review (No. 19-71615) with instructions for the FERC to vacate its orders. The Court likewise dismissed FERC's consolidated appeal (Nos. 19-16833, 19-16834) with instructions for the bankruptcy court to vacate its order. In taking these actions including vacating the orders), the Court expressed no opinion on the merits of the dispute, which it left for future courts to evaluate. Reporting on this matter is concluded.

- **PennEast Project (18-1128)**
  Underlying FERC Proceeding: CP15-558[202]
  Petitioners: NJ DEP, DE and Raritan Canal Commission, NJ Div. of Rate Counsel

Abeyance continues of the appeal before the DC Circuit of the FERC's orders granting certificates of public convenience and necessity to PennEast Pipeline Company, LLC ("PennEast")[203] for the construction and operation of a new 116-mile natural gas pipeline from Luzerne County, Pennsylvania, to Mercer County, New Jersey, along with three laterals extending off the mainline, a compression station, and appurtenant above ground facilities ("PennEast Project"). The cases are being held in abeyance "pending final disposition of any post-dispositional proceedings [ ] before the United States Supreme Court resulting from the Third Circuit's decision in No. 19-1191 (In re: PennEast Pipeline Company, LLC (3rd Cir. Sep. 10, 2019)), or other action that resolves the obstacle PennEast poses". That decision held that the Eleventh Amendment barred condemnation cases brought by PennEast in federal district court in New Jersey to gain access to property owned by the State or its agencies, thus calling into question the viability of PennEast's proposed project route, and the certificates issued in the underlying case. Until the Third Circuit case is resolved, which is in the midst of proceedings before the Supreme Court, the DC Circuit will not take up this case. The last Joint Status Report was filed on September 28, 2020, noting developments since the June 29, 2020 Status Report, and reporting that none of the events "constitute any of the conditions that [the DC Circuit] enumerated in its October 1, 2019 Order as triggering an obligation to file a motion governing future proceedings."

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

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

[203] PennEast is a joint venture owned by Red Oak Enterprise Holdings, Inc., a subsidiary of AGL Resources Inc.; NJR Pipeline Company, a subsidiary of New Jersey Resources; SJI Midstream, LLC, a subsidiary of South Jersey Industries; UGI PennEast, LLC, a subsidiary of UGI Energy Services, LLC; and Spectra Energy Partners, LP.

- **Opinion 569/569-A: FERC's Base ROE Methodology (16-1325, 20-1182, 20-1227, 20-1240, 20-1241, 20-1248, 20-1251, 20-1267, 20-1275)**
  Underlying FERC Proceeding: EL14-12; EL15-45[204]
  Petitioners: MISO TOs, FirstEnergy, Transource Energy

The MISO Transmission Owners (TOs), FirstEnergy and Transource 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. Motions to govern future proceedings in the MISO TOs' case are now due August 10, 2020. The FirstEnergy case was assigned case number 20-1227; the Transource case, 12-1240. On July 10, 2020, the Court consolidated the FirstEnergy and Transource cases. Initial submissions in the FirstEnergy case were filed July 30, 2020.

On August 5, 2020, the FERC asked the Court to hold the appeals in abeyance, including the filing of the certified index to the record, for a period of four months, ending December 7, 2020, with parties to file motions to govern further proceedings at the end of that period. The FERC requested abeyance to permit it to issue a further order on rehearing of challenged orders. MISO TOs opposed the FERC's request on August 14. The FERC responded to that opposition on August 20, 2020. The Court has not as of the date of this Report acted on the FERC's August 5 motion. Since the last Report, however, the Court consolidated a number of cases and indicated that a schedule for the filing of briefs will be established by future order.

[204] *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).

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

IV. OATT Amendments/Coordination Agreements

V. Financial Assurance/Billing Policy Amendments

VI. Schedule 20/21/22/23 Updates

VII. NEPOOL Agreement/Participants Agreement Amendments

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XII. Misc: Administrative & Rulemaking Proceedings

XIII. Natural Gas Proceedings

XIV. State Proceedings & Federal Legislative Proceedings

XV. Federal Courts

NEPOOL Participants Committee

Future Pathways

Round 2: Focus on Energy Only Market and Alternative Resource Adequacy Constructs:

Preliminary Observations and Request for Input

Frank A. Felder

Nov. 5, 2020

Agenda and Inventory of Pathways

Today's Agenda

1. Quick Overview and Recap
2. Energy Only Market (EOM) & Shortage Pricing
3. Alternative Resource Adequacy Constructs (ARAC) (alternatives to FCM, FCEM & ICCM)
4. Next Steps
5. Questions, Comments, and Request for Input
6. Appendix: Background, Abbreviations & References

Inventory of Identified Pathways

1. Forward Clean Energy Market (FCEM)
2. Integrated Clean Capacity Market (ICCM)
3. Carbon Pricing (CP)
    1. With the RGGI framework (RGGI+)
    2. Carbon pricing external to ISO-NE
    3. Net Carbon Pricing (LMP-NC)
4. Energy Only Market (EOM)
5. Alternative Resource Adequacy Constructs (ARAC)
    1. Fixed Resource Requirement (FRR)
    2. FCM with Balancing Resources (FCM-BR)
    3. Voluntary-Residual Capacity Market
    4. Standardized Fixed-price Forward Contract (SFPFC)
    5. Regional Integrated Resource Planning (Regional-IRP)
    6. State Integrated Resource Planning (State-IRPs)
    7. Net FCM

Quick Recap

Project Goal

Compares Pathways across two key questions:

Whether and to what extent the Pathway supports the clean energy policies of States?

Whether and to what extent the Pathway garners efficiency of regional markets?

Presentation on Dec. 3, 2020

Project Report: Draft targeted for late Nov.; final in late Dec.

ISO Retained Functions and Caveats

For the Pathways and Variations, it is presumed that ISO-NE would continue to conduct energy dispatch, unit commitment, maintenance scheduling, transmission planning, market monitoring and mitigation, and market administration and settlement

For the Pathways and Variations, markets are used to procure energy, capacity (except for EOM and some ARACs), ancillary services, although the type, structure and administration of these markets may vary across Pathways

Pathways are inextricably linked to regional and State specific policies

High-level Findings (Preliminary)

1. Whether the MOPR applies to a particular pathway, e.g., the Forward Clean Energy Market (FCEM) or the Integrated Clean Capacity Market (ICCM), affects whether "double payment" for clean energy occurs and whether price suppression occurs

2. As Variable Renewable Energy Resources (VRERs) increase, whether using a resource adequacy construct to maintain sufficient existing units to provide Balancing Resources (BRs) is appropriate should be considered
   - More definition of BRs, the services that they need to provide, and the reliability criteria that they are used to satisfy is needed

3. Energy Only Market (EOM) addresses the "double payment" issue, maintains a regional market, even more so if carbon pricing is added, but additional changes to the ancillary services markets may be needed to ensure sufficient BRs
   - One regional market metric is the percentage of revenue a resource obtains from the ISO-NE markets

High-level Findings (Preliminary), con't

4. Some Alternative Resource Adequacy Constructs (ARACs) may address the MOPR issue but by reducing regional markets and associated efficiency benefits

5. All but one ARAC, FCM-BR, do not have a mechanism for ensuring sufficient BRs

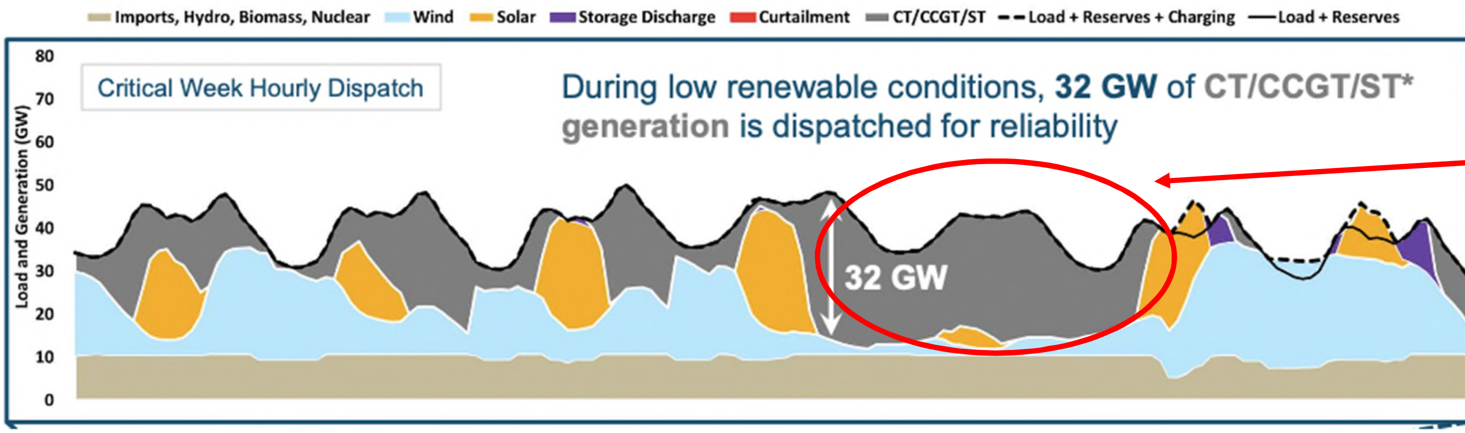
6. There is a possible alternative, Net FCM, that addresses the MOPR issue while maintaining regional markets that should be considered

7. The anticipate major replacement of generation resources throughout New England with new capacity at new locations with very different operating characteristics than historical generation strongly suggests that transmission planning and cost allocation need to be considered when evaluating possible Pathways to avoid costly investment decisions

MOPR Applicability High-level Finding (#1) (Preliminary)

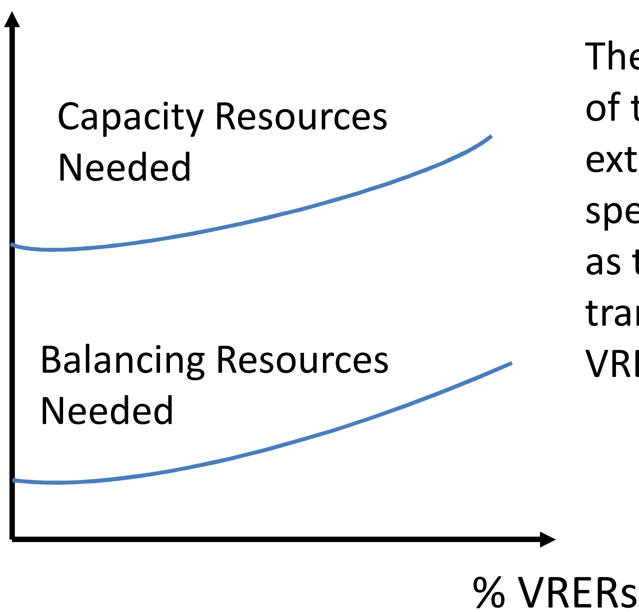
Resource Adequacy	**Does the MOPR Apply?**
Forward, Mandatory Capacity Market	Yes, based upon FERC ruling (a new Commission could change this) *Not clear why or how FCEM or ICCM avoids the MOPR issue*
Carbon Pricing with FCM (or FCEM or ICCM)	Yes, but mitigates MOPR impact by increasing energy revenue and therefore reducing capacity offer floor *May not eliminate the double payment issue and raises concerns about increasing wholesale electricity prices (mitigated with net-carbon pricing)*
Mandatory Capacity Market without forward obligation	Likely, given FERC's current MOPR order *FCM, FCEM and ICCM depend on a multi-year forward commitment*
Voluntary Capacity Market	Perhaps not, given that PJM FRR allows for self-supply, which in effect makes the capacity market voluntary
Capacity Requirement without a Market	No likely, given that FRR allows for a capacity requirement
Standardized Fixed-price Forward Contract (SFPFC)	Unclear, may depend on who administers the SFPFC auction
Energy Only Market	No, removes the mechanism that the MOPR is attached to and eliminates the double payment

High-level Finding (#2) Re: Variable Renewable Energy Resources (VRERs) and Balancing Resources

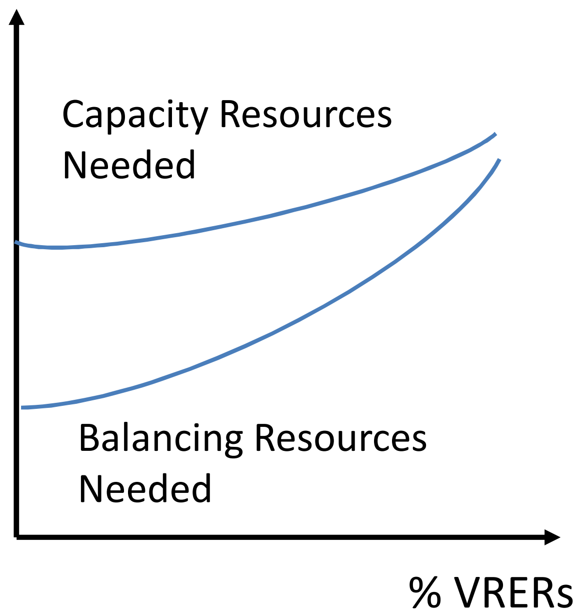


E3, Electric Reliability Under Deep Decarbonization in New England, Aug. 4, 2020, p. 38

How likely is this week and what balancing services are needed to address it?



The shape and location of these lines affect the extent and timing of specific BR mechanisms as the system transitions to more VRERs



BRs Definition, High-level Finding (#2) (Preliminary)

1. More clarity is needed regarding the definition, services, and reliability requirements of BR
    1. What is the definition of BRs?
    2. What are the balancing services that are needed?
    3. What are the reliability requirements that set the amounts of needed BRs?
    4. How are the amounts of each type of balancing services determined?
2. Some BRs provide capacity, some do not, and not all BRs are generators (e.g., synchronous condensers)

Variable Energy Resources	**Balancing Resources (BR)**	**Capacity Resources (CR)**
PV Solar Wind (onshore and offshore) Run of river hydro Others?	Combined cycle Flexible steam units Flexible gas turbines Some storage Dispatchable hydro Some demand response Imports? Others?	Combined cycle Steam units Gas turbines Some storage Some dispatchable hydro Some run of river hydro Some demand response Imports Others?

Understanding how much BRs are needed for different levels of renewable penetration and whether the FCM without modification will cost-effectively procure BRs would help inform the value of the FCM

Energy Only Market Pathway Description

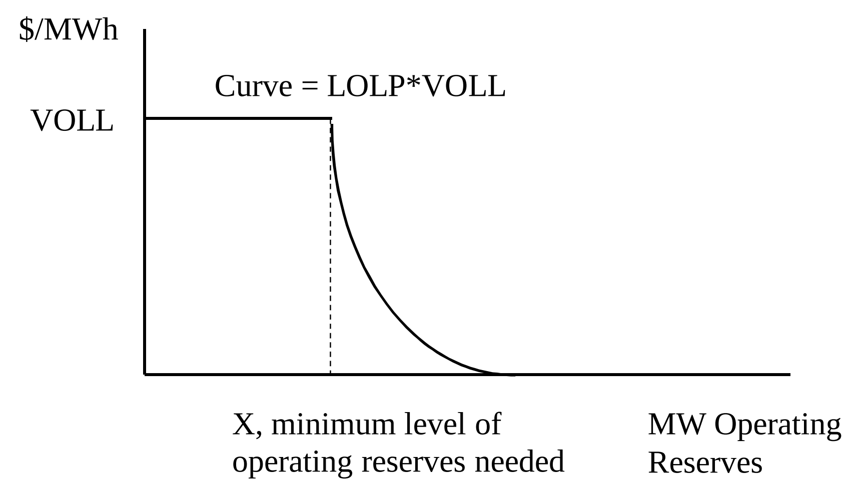
Texas energy only market model (aka Operating Reserve Demand Curve (ORDC))

ORDC based upon Value of Lost Load (VOLL) and Loss of Load Probability (LOLP)

Key Design Variables

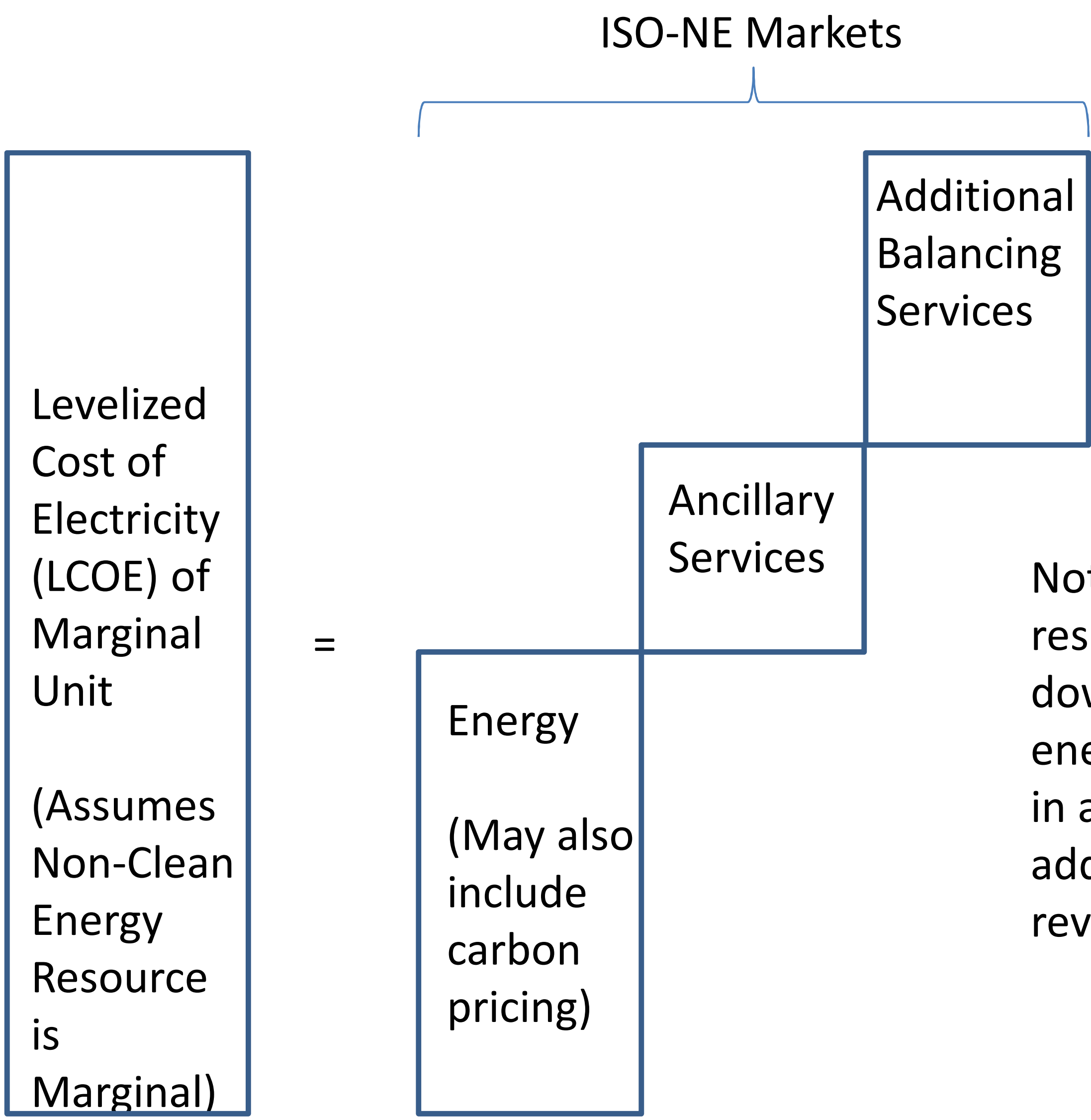
- VOLL
- X, min. level of op. reserves needed
- Have additional reliability adders to offset price suppression?
- Whether to co-optimization with economic dispatch?
- Whether there are price adders for multiple reserve products?
- Whether there are zonal/locational reliability adders?

X, minimum level of
operating reserves needed



Energy Only Market Revenue Streams

Not drawn to scale



Note: States' clean energy resource requirements will likely put downward pressure on wholesale energy prices, requiring increase in ancillary service prices and/or additional balancing service revenues to ensure reliability

EOM High-level Findings (#3) (Preliminary)

1. EOM addresses the MOPR double-payment issue and allows States to individually or collectively pursue their clean energy policies as they see fit
2. EOM and existing ancillary service markets may not provide sufficient flexibility and ramping services (i.e., sufficient BRs)
    1. The need for BRs due to the penetration of Variable Renewable Energy Resources (VRERs), may be addressed either via current wholesale market mechanisms (energy, ancillary services) and/or new constructs
3. EOM can be combined with Carbon Pricing (CP);
    1. Proportion of revenue recovery shifts to DA and RT energy markets away from States' clean energy funding mechanisms
4. Shortage pricing, the key feature of EOM, can be combined with FCM and its variations (e.g., FCEM and ICCM) and ARRCs
    1. Shifts focus of revenue recovery to DA and RT energy markets away from capacity markets and constructs

ARACs High-level Findings (#4-5) (Preliminary)

1. Many ARACs address the MOPR double-payment issue but by reducing the role of a centralized, regional market for capacity that is economically linked to the energy and ancillary services markets
2. Some ARACs have the ISO-NE set resource adequacy requirements (FCM-BR, FRR and Voluntary-Residual Capacity Market) whereas other constructs could have States set the requirements (SFPEC, Regional-IRP, and State-IRPs)
3. Since ARACs are resource-adequacy based (FCM-BR also has a BR demand curve), with an increasing need for BRs, additional mechanisms for BRs may be necessary

Fixed Resource Requirement (FRR) Pathway Description

- Based upon PJM's FRR (but accommodating LSEs)
- LSEs can opt out of the capacity market by demonstrating that they have sufficient resources available to meet the reliability requirement for the LSE's load
- Election is for a minimum number of years, e.g., 5 years
- LSEs capacity plans that are insufficient pay an FRR Commitment Insufficiency Charge
- Capacity resources must meet the same Capacity Performance Requirements as resources participating in the FCM

FRR Findings (Preliminary)

- Addresses the MOPR double payment issue
- Design for integrated utilities in non-retail energy market States instead of LSEs who have multi-year commitments for resources
  - May not align well with some clean energy procurement strategies such as RPS/RES, which are annual
- LSEs loads over multiple years may be too volatile to make FRR a viable option
- Does not address the need for BRs and may compound the problem if the capacity resources in the FRR are not BRs
- Reduces the regional reach of the FCM and associated efficiency benefits

FCM-Balancing Resources (FCM-BR) Pathway Description

- Eliminate MOPR for all resources and replaces CASPR
- Use Effective Load Carrying Capability (ELCC) to determine Qualified Capacity for all resources participating in the FCM
- Construct a Marginal Reliability Impact (MRI) demand curve that Balancing Resources (BRs) would get paid (basically an adder to the primary FCA system price)
- One approach: The total payment to BRs at the total quantity of Energy Security Improvement (ESI) requirement equals Net CONE

  ESI = GCR+RER+EIR

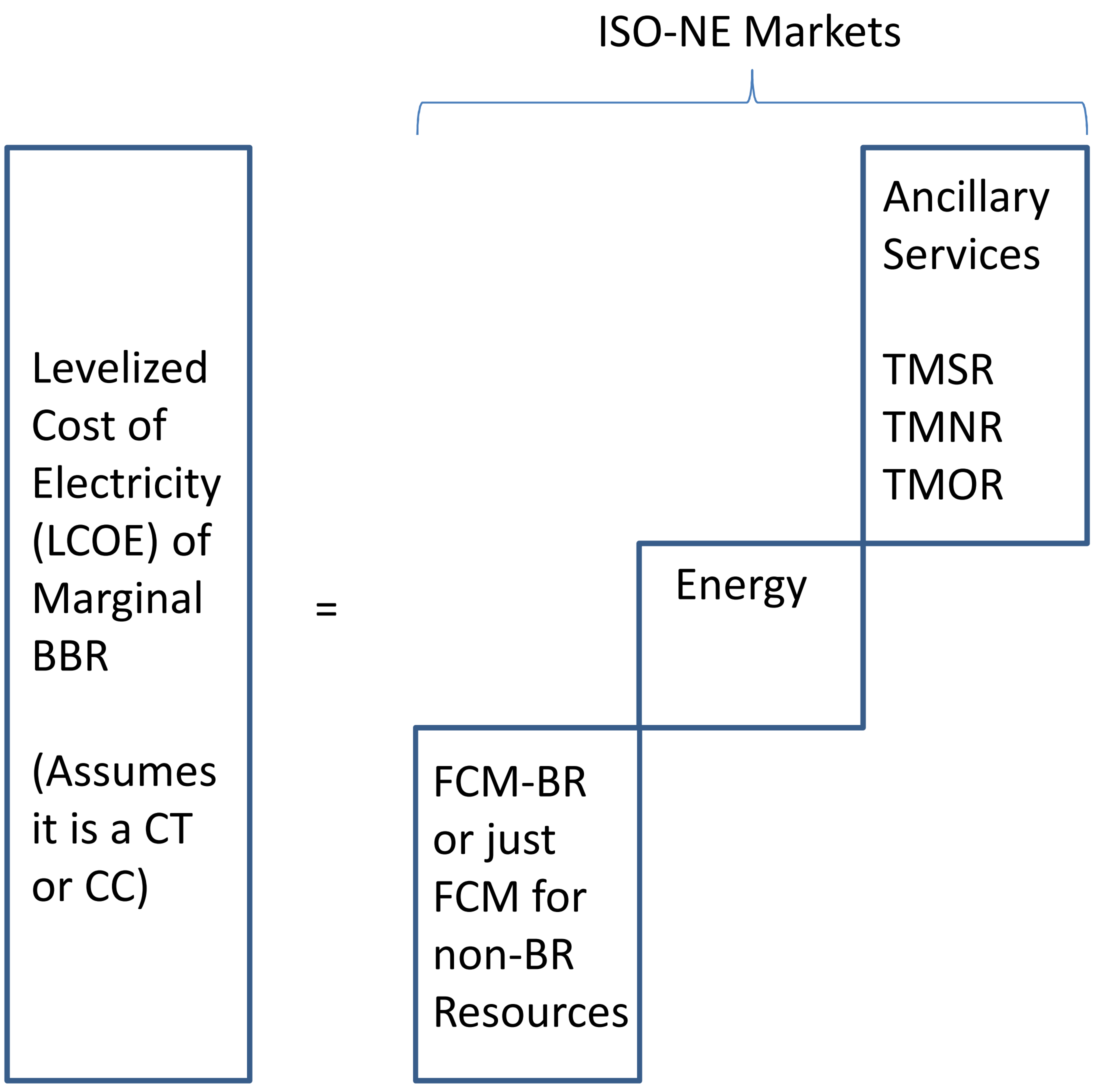
  GCR: General Contingency Reserves

  RER: Replacement Energy Reserves

  EIR: Energy Imbalance Reserves
- Additional recommendations: make FCM voluntary and use sealed bid auction

Ref. Energy Market Advisors, Oct. 15, 2020, http://nepool.com/uploads/FGP_S_Public_Power_Systems.pdf

FCM-BR Revenue Streams



<u>Abbreviations:</u>

TMSR: 10-minute Spinning Reserves
TMNR: 10-minute Non-Spinning Reserves
TMOR: 30-minute Operating Reserves

Not drawn to scale

FCM-BR High-level Findings (Preliminary)

- Builds upon existing construct as opposed to developing a new one
- Addresses price suppression due to State Sponsored Resources for BR resources (but not non-BR ones)
- May still trigger MOPR and therefore not address the double payment issue, i.e., does not guarantee that State Policy Resources will clear the FCA auction given out of market support
  - Although many non-State Sponsored resources would be eligible for the additional BR revenues, not all are eligible and would be competing against State Sponsored resources

Ref. Energy Market Advisors, Oct. 15, 2020, http://nepool.com/uploads/FGP_S_Public_Power_Systems.pdf

Regulatory-Market Tradeoffs of ARACs

Regulators Set Quantities, Technologies & Timing

Markets Set Prices

Vertical Integration

State IRPs

Regional IRP

SFPFC*

Resource capacity determined Outside of ISO-NE

FRR

FCM-BR

Voluntary Capacity Market

Energy Only Pricing

FCEM or ICCM Options

Carbon Pricing

Resource capacity set by ISO-NE

The Energy Shortage component of Energy "Only" Pricing can augment other ARACs

Additional balancing requirements, services and procurement mechanisms may be needed

*Standardized Fixed-price Forward Contract, presentation by Prof. Wolak to follow

ARACs Design Variables

Pathway	Capacity Requirement	Centralized Capacity Market	Forward Requirement
EOM	No	No	No
Voluntary Capacity Market	Yes	Yes	No
FCM-BR	Yes	Yes	Yes
FRR	Yes	Yes	Yes
Capacity Requirement	Yes	Yes	Yes
SFPFC	No, but has firm energy requirement	No, but mandatory SFPFC auction	Yes, via firm energy requirement
Regional IRP	States Collectively	No	Yes, but via IRP procurement
State IRP	Individual States	No	Yes, but via IRP procurement

Carbon and Shortage Pricing Variations of EOM & ARACs

<table>
<tr><th>Resource Capacity Requirements</th><th>Variations</th><th>Comment</th></tr>
<tr><td>Energy Only Market</td><td>Carbon Pricing at Social Cost of Carbon (SCC)</td><td>Not aware of any stakeholder support for this pathway</td></tr>
<tr><td>FCM-BR</td><td rowspan="6">Carbon Pricing at Social Cost of Carbon (SCC)

and/or

Shortage Pricing</td><td rowspan="6">Carbon pricing reduces impact of MOPR, if applicable, and increases revenues obtain via wholesale electricity markets, enhancing the regional market and efficiency

Shortage pricing may provide a “resource adequacy backstop” particularly as capacity procurement becomes more decentralized and diffused</td></tr>
<tr><td>Capacity Requirement with Voluntary Capacity Market</td></tr>
<tr><td>FRR</td></tr>
<tr><td>LSE Energy Requirement</td></tr>
<tr><td>Regional IRP</td></tr>
<tr><td>State IRPs</td></tr>
</table>

High-level Tradeoffs: EOM & ARACs

<table>
<tr><th>Resource Capacity Requirements</th><th>Supports States Clean Energy Policies</th><th>Garners Efficiency of Regional Markets</th><th>Additional Mechanism for Balancing</th></tr>
<tr><td>Energy Only Market</td><td>Not interfere with States’ policies; MOPR not apply and States have flexibility to pursue clean energy policies without double payment</td><td>Somewhat; single set of wholesale energy prices but affected by States’ clean energy policies and associated out of market payments</td><td rowspan="6">Additional balancing requirements, services, and procurement mechanisms may be needed</td></tr>
<tr><td>FCM-BR</td><td rowspan="2">Depends if MOPR applies</td><td rowspan="2">Somewhat; integrated energy market and capacity(or firm energy) requirement, although States’ clean energy policies may limit benefits of regional markets</td></tr>
<tr><td>Capacity Requirement with Voluntary Capacity Market

SFPFC</td></tr>
<tr><td>FRR</td><td rowspan="3">Yes, “double payment issue” is avoided and States have flexibility to pursue clean energy policies without double payment</td><td rowspan="3">No regional capacity product; regional benefits depends on success of regional planning, if any</td></tr>
<tr><td>Regional IRP</td></tr>
<tr><td>State IRPs</td></tr>
</table>

Another ARAC for Consideration, Net FCM, High-level Finding (#6) (Preliminary)

1. Assume MOPR exists and both a FCEM and FCM are desirable

   To avoid double payment:

2. Run FCEM first
3. Based upon clean energy resources that clear the FCEM, calculate the net capacity requirement, i.e., the remaining needed capacity to meet resource adequacy requirement using the current rules for adjusting the capacity values of VRERs
4. Run the FCM based on the net capacity requirement (and if concerned about BR, use FCM-BR)

   Advantages:

5. Does not trigger MOPR because clean energy resources are not selling capacity but are reflected in the required amount of capacity that load must purchase
6. Load only purchases the net amount of needed capacity after deducting the capacity contribution from clean energy resources
7. Although clean energy resources do not get paid capacity revenue, load does not pay for capacity twice
8. Provides States an incentive to use the FCEM because if they do not, their load double pays for capacity

Next Steps

1. Opportunities for written feedback and comments to this (and future) presentations are available

2. All comments will be considered, although comments that improve and contribute to the analysis of tradeoffs of Pathways and Variations will be the more helpful than advocacy

   *Please provide any written feedback on this presentation or other Pathways to NEPOOL Counsel (slombardi@daypitney.com) by COB Thursday, November 19 or sooner; all comments will be posted on the NEPOOL website

3. Preparation of presentation for Dec. 3 NEPOOL Participants Committee Meeting

4. Goal to issue final report by end of the year, which will be circulated as a draft for comment, targeted for end of Nov.

QUESTIONS AND COMMENTS

Abbreviations

ACP: Alternative Compliance Payment

ARAC: Alterative Resource Adequacy Constructs

CCS: Carbon Capture and Sequestration

CEAC: Clean Energy Attribute Credit

CONE: Cost of New Entry

CP: Carbon Pricing

EOM: Energy Only Market

ERCOT: Electricity Reliability Council of Texas

FCEM: Forward Clean Energy Market

FCM: Forward Capacity Market

FRR: Fixed Resource Requirement

ICCM: Integrated Clean Capacity Market

IRP: Integrated Resource Planning

LOLP: Loss of Load Probability

LSE: Load Serving Entities

MOPR: Minimum Offer Pricing Rule

ORDC: Operating Reserve Demand Curve

PPA: Power Purchase Agreement

RDPA: Reliability Deployment Price Adder

REC: Renewable Energy Credit

RES: Renewable Energy Standard

RGGI: Regional Greenhouse Gas Initiative

RGGI+: RGGI Plus Additional Emission Reductions

RPS: Renewable Portfolio Standard

SCED: Security Constrained Economic Dispatch

SFPFC: Standardized Fixed-price Forward Contract

VOLL: Value of Lost Load

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PESD STANFORD | PROGRAM ON ENERGY AND SUSTAINABLE DEVELOPMENT

Long-Term Resource Adequacy with Significant Intermittent Renewables

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Stanford University

November 5, 2020
NEPOOL/Future Grid Meeting

Future Electricity Supply Industry

Electricity supply industry in a low-carbon world will have a significant amount of intermittent renewables

- Intermittent renewable energy shares in excess of 50 percent
- Significant amount of distributed solar generation capacity

Large intermittent renewables share will require

- Investments in both grid-scale and distributed storage
- Active demand-side participation by customers with interval meters using dynamic retail electricity prices
- Automated distribution network monitoring and on-site load-shifting technologies

Market design should support business models that lead to efficient levels of investment in these technologies

Future Electricity Supply Industry

Policy Question: What long-term resource adequacy mechanism will facilitate a least-cost transition to this future electricity supply industry with these pricing policies and technologies?

- Capacity payment mechanism--Increasingly expensive approach to long-term resource adequacy, particularly for regions with a large share of intermittent renewables
  - Limits economic benefits from dynamic pricing and storage and load flexibility investments
- Standardized long-term energy contracting--Least cost approach to long-term resource adequacy for future electricity supply industry
  - Supports storage investments and investments in flexibility technologies on supply and demand side of market

Need for Resource Adequacy Mechanism

In former vertically-integrated geographic monopoly regime, monopoly is responsible for ensuring there are sufficient resources to meet demand

- Regulator penalizes monopoly for supply shortfalls

In wholesale market regime no single entity is responsible for ensuring sufficient resources to meet system demand

- Independent System Operator (ISO) can only operate market with resources it has
- Generation unit owners can only supply energy from the generation units they control
- Retailers can only purchase the energy that generation unit owners supply to wholesale market

Conclusion—Unless regulator treats electricity like any other product (see next slide), wholesale market regime requires a long-term resource adequacy mechanism

Need for Resource Adequacy Mechanism

A long-term resource adequacy mechanism is necessary because of "reliability externality"

- Unwillingness of regulator to commit to use real-time price of energy to clear market under all possible system conditions creates a "reliability externality"
- Lack of interval meters often used to justify this unwillingness of regulator "to treat electricity like any other product"

All consumers know that random curtailment will occur if aggregate supply is less than aggregate demand, so no customer faces full expected cost of failing to procure adequate energy in forward market

Because of existence of "reliability externality," in markets with a finite offer cap regulator must mandate a long-term resource adequacy mechanism

- *Ensure adequate supply to meet system demand under all future system conditions and allowed short-term prices*
- *Make most efficient use of all resources available to ISO*

Historical Long-Term Resource Adequacy Challenge

- Initial Conditions: Electricity supply industry with dispatchable (typically, thermal) generation resources, mechanical meters, and offer cap on short-term wholesale market
- Major concern: Sufficient installed capacity to meet system demand peak
- Mechanical meters: Only allow measurement of total electricity consumption between consecutive meter reads
  - Typically done on monthly or bi-monthly basis
  - Precludes use of dynamic prices to reduce system peaks
- Offer cap on short-term market: Can prevent units that run infrequently to recover their total cost

Capacity Payments: Historical Solution to Problem

- Assign all retailers firm capacity obligations equal to a multiple of their annual peak demand
  - Between 110 to 120 percent, depending on region
- All generation units assigned firm capacity quantity equal to amount of energy unit can produce under stressed system conditions
  - For thermal resource this is typically equal to nameplate capacity times the availability factor of the unit
  - For hydro units, typically based on historically worst hydrological conditions
    - For example from Colombia, see McRae and Wolak (2016) "Diagnosing the Causes of the Recent El Nino Event and Recommendations" available from web-site.
  - For solar and wind resources, it is extremely difficult to determine firm capacity of generation units
    - Firm capacity of a MW of wind or solar capacity declines with share of wind or solar energy in system demand because of high degree of correlation in output across locations
      - For case of California, "Wolak, Frank A. "Level versus Variability Trade-offs in Wind and Solar Generation Investments: The Case of California." *The Energy Journal* 37, (2016).

Firm Capacity of Intermittent Resources

- Firm capacity of solar or wind resource typically determined by effective load carrying capacity (ELCC)
  - If stressed system conditions occur when it is dark, firm capacity of solar generation unit should be zero
  - If stressed system conditions occur when wind is not blowing, firm capacity of wind generation unit should be zero
- Assignment of firm capacity to intermittent renewable resources has a significant political component
  - Values used for August 2020 were 27% for solar PV and solar thermal and 21% for wind
    - Rolling blackouts occurred in late evening on August 14 and 15
  - Recent study by three CA investor-owned utilities estimated effective load carrying capability (ELCC) of solar PV at ~5 percent of nameplate capacity
    - *2020 Joint IOU ELCC Study*, prepared by Astrape Consulting
- Conclusion: Firm capacity approach to long-term resource adequacy poorly suited to regions with high shares of intermittent renewable energy

Summary Comments on Capacity Mechanisms

Capacity payments are a expensive mechanism for attempting to achieve long-term resource adequacy in regions with significant intermittent generation resources

- Does not address primary reliability challenge in intermittent-renewable-dominated wholesale markets
  - Energy shortfalls
- No guarantee that adequate capacity will be built
  - Depends on level of capacity payment
- Little success with capacity payments in international markets outside of Latin America countries with cost-based energy markets, e.g., Chile
  - See Galetovic, Munoz, and Wolak, "Capacity Payments in a Cost-Based Wholesale Electricity Market: The Case of Chile" (available on web-site)
- Market-based pricing of capacity extremely challenging, particularly locationally
- Little evidence that markets with capacity payments in the US have achieved higher levels of short-term or long-term reliability

Long-Term Resource Adequacy for Markets Dominated by Intermittent Renewables

Question is not an energy-only market versus capacity market

- Key Point: A long-term resource adequacy mechanism is necessary in any energy market with a finite offer cap because of the reliability externality
- Higher offer caps on short-term market only reduce magnitude of reliability externality, but do not eliminate it

How to maximize benefits of market mechanisms while still providing regulator with assurance that demand will equal supply under all possible future system conditions

- Long-term resource adequacy mechanism that provide consumers with what they want
- Requires consumers pay for what they want
  - Some long-term resource adequacy mechanisms involve many "small" charges that sum up to higher costs for consumers
- Allow market participants maximum flexibility to determine least cost way to provide consumers with what they want

Consumers want system demand for electricity to be met under all possible future system conditions

- Long-term resource adequacy mechanism should focus on having sufficient resources to meet system demand, not demand for each individual retailer
- Electricity supplied to a load comes from grid, not from specific generation units
- Recall that in wholesale market regime, no market participant responsible for meeting system demand all hours of the year

Energy-Contracting Resource Adequacy Process

Mandate standardized forward contract holdings by retailers for pre-specified fractions of system demand at various horizons to delivery

- 100% of demand one year in advance
- 97% of demand two years in advance
- 95% of demand three years in advance
- 92% of demand four years in advance
- Percentages are not set in stone, nor is length of contracting mandate

Contracts are shaped to actual hourly system demand within delivery period

- QD_h = actual system demand in hour h of delivery period of contract for h=1,2…,H
- QC_{total} = amount of energy sold in standardized contract for delivery period
- $QC_{jh} = \left(\frac{QD_h}{\sum_{h=1}^{H} QD_h}\right) QC_{j,total}$ for h=1,2,…H is forward contract obligation of seller j for hour h
- Note that $QD_h = \sum_{j=1}^{N} QC_{jh}$ for all h, where N = total number of sellers of contracts

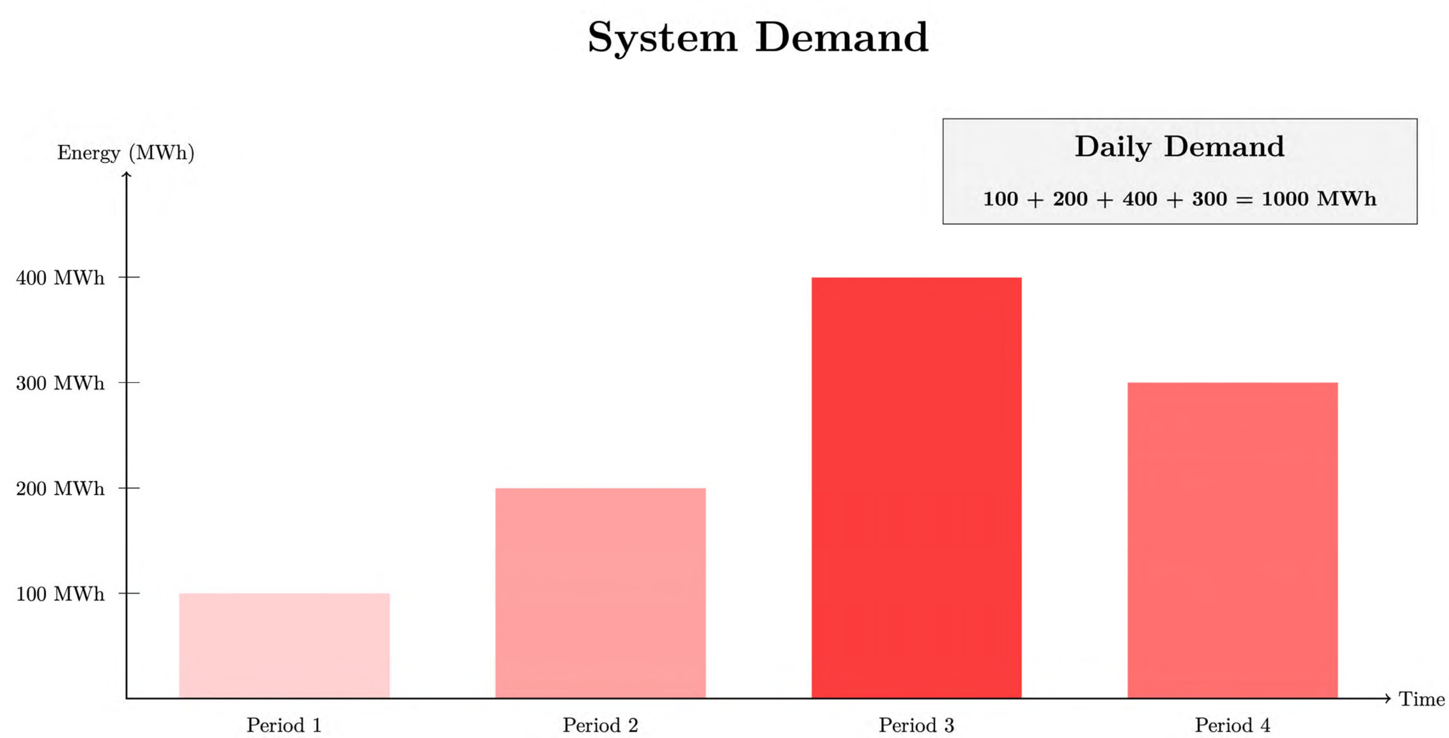
Total energy shaped to realized pattern of system demand sold in standardized contract

- Note that during any hour of the year, there is a value of $QC(h)_{total}$, the remaining amount of system-wide eligible standardized contract energy that can be delivered in hour h
  - $QC(h)_{total}$ satisfies the following difference equation
  - $QC(h+1)_{total} = QC(h)_{total} - QC_h + \Delta QC(h)_{total}$
  - $\Delta QC(h)_{total}$ = purchases of additional QC_{total} that is eligible to deliver during hour h and h+1

Note that QC_h varies with realized values of QD_h

- Sellers of contracts have ability to manage this quantity risk through use of own generation units or through their hedging arrangements
- Sellers charge price for standardized contract that incorporates cost of managing quantity risk

Energy-Contracting Resource Adequacy Process



Realized Total System Demand ($\sum_{h=1}^{4} QD_h$) is equal 1,000 MWh and Has the Above Hourly Values, QD_h, h=1,2,3, and 4

Energy-Contracting Resource Adequacy Process

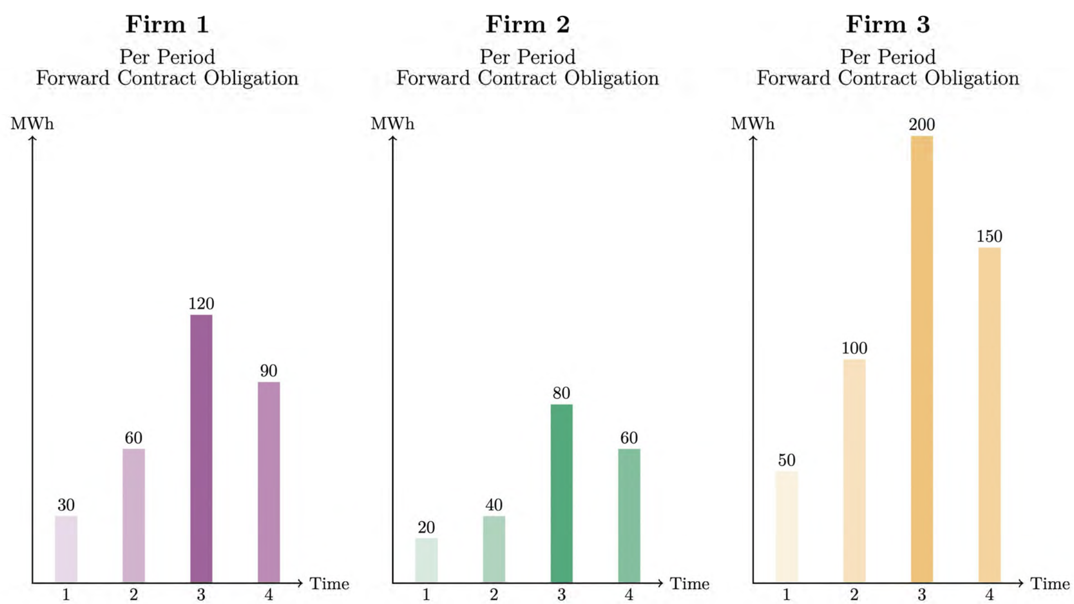
There are Three Firms:

Firm 1 sells 300 MWh

Firm 2 sells 200 MWh

Firm 3 sells 500 MWh

Total Amount Sold by Three Firms = 1000 MWh



Period-Level Values of QC_{hk} for Total Sales $Q_{total,k}$ of Each Firm k=1,2,3

$\sum_{k=1}^{3} QC_{Total,k} = 1000$ MWh = $\sum_{k=1}^{4} QD_h$

Energy-Contracting Resource Adequacy Process

Standardized contracts can run for different delivery horizons

- Multi-year, single year, quarterly or monthly

Delivery on initial multi-year contracts should begin far enough in advance of delivery that new sources of supply can compete to provide energy

- At least three years between close of auction and delivery of energy
- Time horizon necessary for new entry to compete with existing generation unit owners to supply standardized forward contract

Contracts can be procured to meet actual system demand on behalf of retailers and large consumers through periodic standardized auctions

- Annually, Quarterly, Monthly

Simple auction mechanism can be used to procure energy because single product is being purchased—energy shaped to hourly system demand

- Can run simple declining clock auction to purchase standardized contract for energy

Energy-Contracting Resource Adequacy Process

Contracting mandates (percentages) are regulator's security blanket to ensure adequate supply of energy under all possible system conditions in future

- Allows offer cap on short-term energy market
- Can increase offer caps over time because system demand is hedged

No capacity requirement

- Lets suppliers figure out least cost way to meet system demand for energy and ancillary services
  - By allocating quantity risk associated with hourly variation in QC(h) among suppliers creates supply of operating reserves that can sell ancillary services
- Creates level playing field for demand-side and supply-side solutions
- Focuses on primary reliability problem in markets with significant amounts of renewables—adequate energy to serve demand
  - There has never been a shortage of generation capacity in California and other high renewables regions--New Zealand, Colombia, Brazil, and Chile--in wholesale market regime

Energy-Contracting Resource Adequacy Process

Periodic standardized auctions run by Market Operator overseen by State PUCs

- Purchases of standardized contracts are made and allocated to all loads based on their monthly (quarterly or annual) share of system load
- QD_k = system demand in MWh during interval k
- C_{ik} = consumption in MWh of retailer or large consumer i during interval k
- QC_{ik} = forward contract coverage of retailer or large customer i during interval k
  - Note that QC_{ik} shaped to system load shape, which may not match hourly load obligation of retailer

If allocation interval is a monthly, then retailers and large consumers have hourly value of QC_{ik} equal to their monthly share of system demand

- Can assign forward contract quantity to retailers and large consumers at lower or higher degree of temporal aggregation than monthly
- Only have to ensure that aggregate hourly difference payments between buyers and sellers of standardized contracts balance

Energy-Contracting Resource Adequacy Process

Overarching goal of standardized energy contracting approach to long-term resource adequacy

- All suppliers and load-serving entities know that actual system demand is fully hedged for all hours of the year
- Hourly output of individual suppliers is not fully hedged
- Hourly demand of individual load serving entities is not fully hedged

All suppliers and load serving entities are free to sign hedging arrangements to manage this residual short-term quantity and price risk

Wholesale energy markets typically start from zero hedging of system demand and market participants engage in hedging arrangements

- Inadequate amounts of hedging because of reliability externality

Standardized long-term contracting approach to resource adequacy starts from position that 100% of actual system load is hedged

- Suppliers and load-serving entities can take on short-term prices through additional hedging arrangements

Energy Contract Allocation Process

There are Four Retailers:

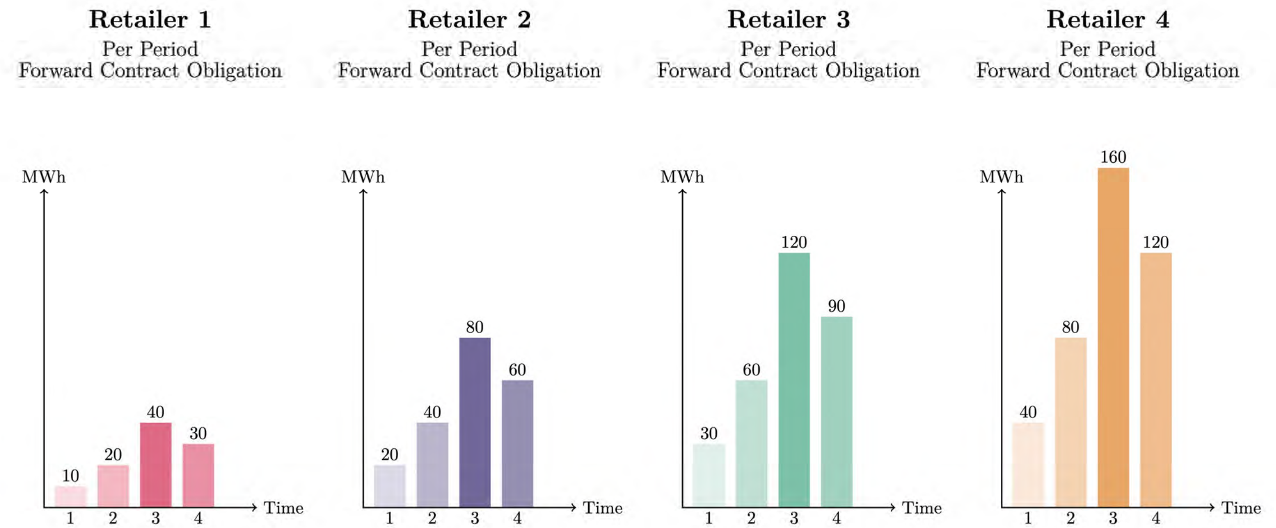
Retailer 1 sells 100 MWh

Retailer 2 sells 200 MWh

Retailer 3 sells 300 MWh

Retailer 4 sells 400 MWh

Total Amount Sold by Four Retailers = 1000 MWh



Sum of Hourly Forward Contract Obligations (QR_{hr}) Assigned to r=1,2,3,4 Retailers is equal to Hourly System Demand (QD_h) and Aggregate Forward Contract Obligations of Generation Unit Owners (QC_{hk})

$$\sum_{r=1}^{4} QR_{hr} = QD_h = \sum_{k=1}^{3} QC_{hk} \;\; for\; h = 1,2,3,4$$

Ex Post True-Up Process for 100% Coverage

There will be a need for true-up auctions to buy or sell standardized contracts for energy after the actual hourly output levels for the year have been determined

- Sales or purchases of incremental standardized fixed-price forward contracts occur and these contracts are allocated to loads using same monthly (quarterly or annual) load fractions

No suppliers and load-serving entities are disadvantaged by over-procurement or under-procurement of standardized fixed-price forward contracts

- Allocation of purchases and sales known before they occur

Ex Post Purchase for 100% Coverage

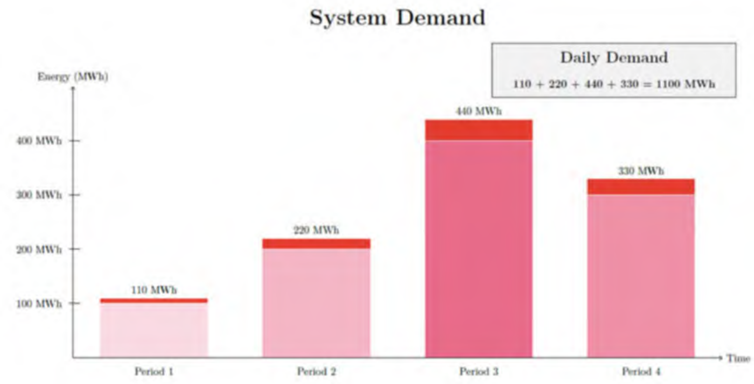


Figure 4: Hourly System Demands (10 Percent Higher)

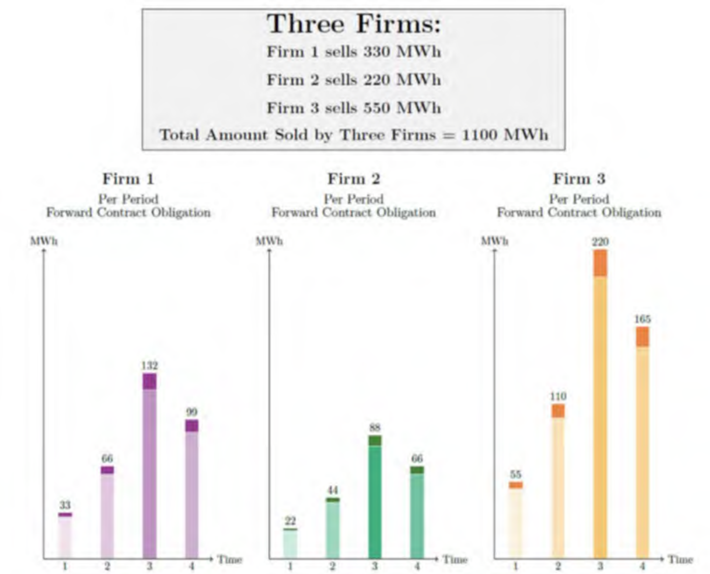


Figure 5: Hourly Forward Contract Quantities for Three Suppliers (10 Percent Higher)

Figure 6: Hourly Forward Contract Quantities for Four Retailers (10 Percent Higher)

Ex Post Sale for 100% Coverage

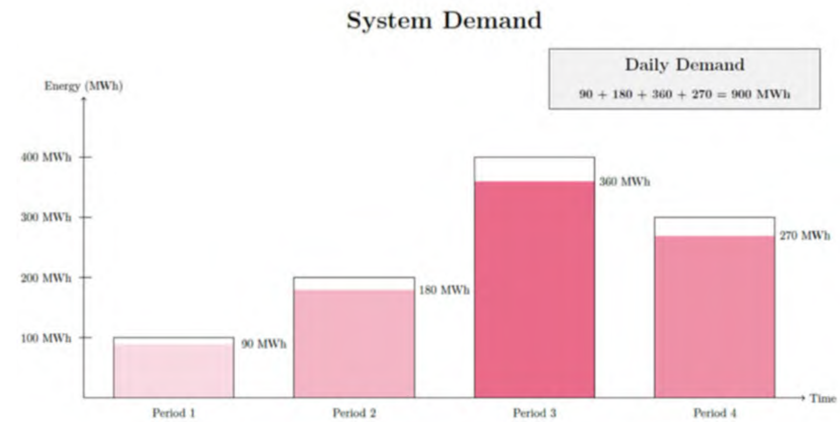


Figure 7: Hourly System Demands (10 Percent Lower)

Three Firms:
Firm 1 sells 270 MWh
Firm 2 sells 180 MWh
Firm 3 sells 450 MWh
Total Amount Sold by Three Firms = 900 MWh

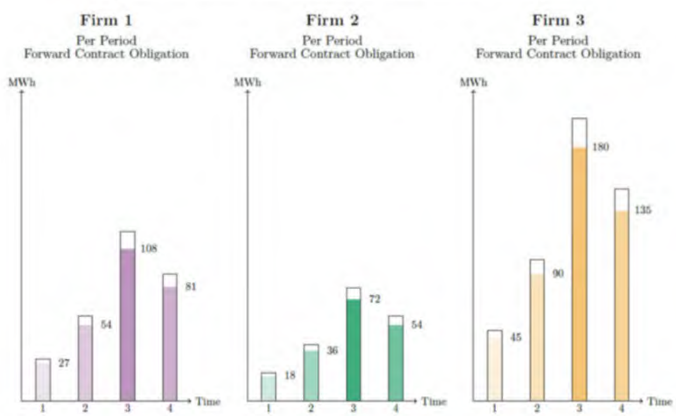


Figure 8: Hourly Forward Contract Quantities for Three Suppliers (10 Percent Lower)

Four Retailers:
Retailer 1 holds 90 MWh
Retailer 2 holds 180 MWh
Retailer 3 holds 270 MWh
Retailer 4 holds 360 MWh
Total Amount Held by Four Retailers = 900 MWh

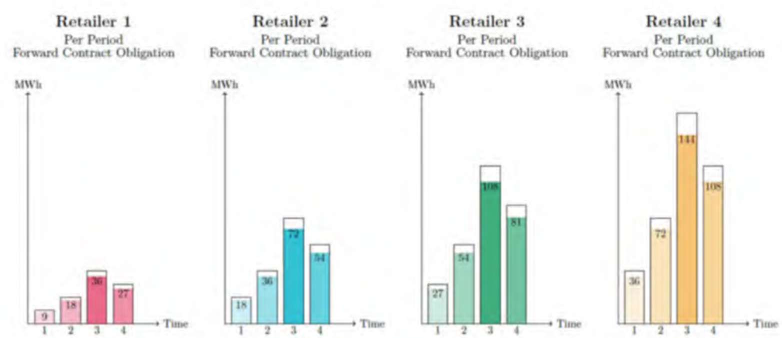


Figure 9: Hourly Forward Contract Quantities for Four Retailers (10 Percent Lower)

Energy-Contracting Resource Adequacy Process

To extent there is concern that appropriate mix of generation capacity may not be constructed to meet ancillary services requirement can run similar forward procurement process for each ancillary service

- ISO/PUCs can run standardized long-term contracts for each ancillary service tailored to hourly demand for that ancillary service
- Contract clear against short-term price for that ancillary service
- Same difference equation used to determine remaining quantity of each ancillary services

Ensures that aggregate demand for each ancillary service is purchased in forward market

- Lets suppliers figure out least cost way to meet system demand for each ancillary services
  - Allocates quantity risk associated with hourly variation in QC(h) for each ancillary services
- Creates level playing field for demand-side and supply-side solutions
- Note that sellers of ancillary service price hedge need not be supplier of ancillary services to short-term market
  - Seller bears full financial consequences of failure to meet forward market obligation for ancillary services

Energy-Contracting Resource Adequacy Process

Aggregate forward contract obligation for all suppliers should cover hourly system demand

- Interval level difference payments can be recovered from retailers and large loads over longer time interval
- Allocate to loads based on their monthly share of system demand

Contracts allocated to individual retailers and large consumers cannot be sold, they must be held to delivery

- This ensures that system demand is fully hedged
- Output of suppliers not fully hedged by their sales of this contract
- Aggregate, but not individual, consumption of retailers and large consumers fully hedged by this contract

Energy-Contracting Resource Adequacy Process

Hourly variable profits for retailers

$$(P(retail) – P(spot))Q(retail)+(P(spot) - P(contract))Q(contract)$$
$$= (P(retail) - P(contract))Q(contract)$$
$$+ (P(retail) – P(spot))(Q(retail)-Q(contract))$$

Hourly variable profits for generation unit owners

$$P(spot)Q(spot) + (P(contract) – P(spot))Q(contract) – C(Q(spot))$$
$$= P(contract)Q(contract) + P(spot)(Q(spot) – Q(Contract) – C(Q(spot)$$

Generation unit owner that produces no energy during hour earns

$$(P(contract) – P(spot))Q(contract)$$

Retailers that consumes Q(contract) during hour earns

$$= (P(retail) - P(contract))Q(contract)$$

Energy-Contracting Resource Adequacy Process

Contract sales by generators and purchases allocated to retailers do not preclude other bilateral contracts

- Standardized contracts for long-term resource adequacy mechanism

Generators can hedge their remaining wholesale price and quantity risk associated with production of energy from their generation units through bilateral contracts

- Standardized contracts designed to jump-start active forward market for energy

Retailers can hedge their remaining wholesale price and quantity risk through bilateral contracts

- QR_{ih} = hourly load obligation of retailer, P_h = hourly wholesale price
- Retailer can use combination of financial instruments and active demand side participation to manage remaining wholesale cost risk
  - $P_h(QR_{ih} - QC_{ih})$ = net energy purchases for retailer i in hour h

Energy-Contracting Resource Adequacy Process

There is no requirement that seller of contract must actually produce electricity sold in standardized forward contract

- Because producing electricity is only way to physically hedge this contract, some market participant will produce the electricity

This requirement addresses issue of futures contract sales by dispatch (thermal) generation unit owners

- These owners will often buy energy from short-term market instead of produce energy when there is a substantial amount of wind and solar energy is being produced

Encourages active demand-side participation in wholesale market (no need for low offers caps on short-term market)

- Consumers protected from high wholesale prices by financial contract coverage of final demand
- Consumers willing to manage short-term price risk can sell bilateral contract to expose themselves to this risk

Energy-Contracting Resource Adequacy Process

Making ISO comfortable with transition to an energy-contracting based resource adequacy mechanism

- The firm energy construct from capacity mechanism should be used to limit the amount of a standardized contract of energy a unit owner can sell
- Do not want unit owners in the aggregate selling more standardized energy than they are able to provide under all possible future system conditions

Dispatchable (typically thermal) resources will typically produce less energy than they are capable of producing during extreme system conditions

Intermittent resources will typically produce more energy than they are capable of producing during extreme system conditions

Mechanism supports necessary cross-hedging between dispatchable resources and intermittent resources required to ensure demand is met under all possible future system conditions

- Intermittent units purchase quantity insurance from dispatchable resources for standardized energy contracts sold
- Intermittent unit owner can purchase cap contract with payment stream max(0,P(spot)-P(strike))Q(contract)

Energy-Contracting Resource Adequacy Process

Ensuring cross-hedging between intermittent and dispatchable resources

- Allow existing resources only to sell up to their firm capacity
  - Amount of capacity unit can produce under stressed system conditions (determined by California ISO and CPUC)
  - Engineers determine this value as they do under existing capacity construct under current Resource Adequacy (RA) process
- Define Annual Firm energy (AFE) in MWh = Firm Capacity (in MW) x 8760

Each participant in standardized contract auction can only sell a total amount of annual energy than is less than or equal to annual firm energy value (AFE)

- Note this AFE value is more about financial viability of supplying this amount of forward energy during delivery period rather than physical viability
- Seller of standardized energy contract that owns intermittent resource, should purchase price and quantity insurance from dispatchable resources to hedge residual net revenue risk
  - Q_{ih} = actual output of supplier j in hour h
  - $P_h(Q_{jh} – QC_{jh})$ = net revenue of supplier j in hour h

Ensures that total standardized contracts for energy sold can actually be delivered under all possible future system conditions

- Under typical conditions, most energy produced by intermittent resources and dispatchable (thermal) resources purchase this energy to meet standardized energy contract obligations
- Under scarcity conditions, most energy produced by dispatchable (thermal) resources and intermittent resources only provide their firm energy

Energy-Contracting Resource Adequacy Process

To make efficient "make versus buy" decision to meet standardized forward contract obligation, thermal suppliers will submit offer to supply energy at marginal cost

- If Price > MC, supplying from unit is cheapest way to meet forward contract obligation
- If Price < MC, buying from short-term market is cheapest way to meet obligation

Allocation of standardized contracts across dispatchable (thermal) suppliers ensures that all are committed to the short-term market at marginal cost for at least the hourly value of QC

Allocation of standardized contracts across intermittent suppliers ensures that they have strong incentive to make arrangements to supply or purchase at least hourly value of QC

- Can purchase price spike insurance from dispatchable (thermal) resources against hourly value of QC
  - To extent ISO and CPUC does not believe renewable resource can provide actual required energy to meet obligations under standardized forward contracts, they should reduce value of firm capacity and therefore AFE that supplier can sell in standardized energy contracts
  - Increases demand for standardized energy from fast start dispatchable resources

Energy-Contracting Resource Adequacy Process

How do new entrants compete in these auctions?

- New entrant sells energy to be delivered three years in the future must show reasonable progress towards having amount of AFE sold in real-time
- If reasonable progress according to CAISO and CPUC is not shown, then contract is liquidated and purchase must be made in upcoming standardized energy auction to meet this shortfall
- Reasonable progress showing can be done every six months through filing by new entrant and site review by CPUC and CAISO staff
- Cost of forward energy purchased to replace energy not supplied by new entrant is allocated to all loads in proportion to load share as described earlier

Energy-Contracting Resource Adequacy Process

Two approaches to managing local long-term resource adequacy
- Allow suppliers to sort out least cost way to meet local reliability constraints
- Can run auctions for standardized contracts that clear against different pricing hubs
  - Different spatial aggregated prices for each retailer
  - Need to determine service territory-level demands that sum to total system demand

Suppliers with fixed-price forward contract obligations that clear against geographically aggregated prices have a strong incentive to keep these short-term prices as low as possible until cover fixed price forward contract obligations

Suppliers that have sold contracts have strong incentive to limit price dispersion across locations
- Meet aggregate demand at lowest possible costs

Each supplier has a strong incentive to make the efficient “make versus buy” decision for its hourly forward contract quantity within in the service territory

Energy-Contracting Resource Adequacy Process

Products must be purchased far enough in advance of delivery to allow new entrants to compete to supply products

- Suppliers with local market power can be disciplined by actions of suppliers that have sold forward standardized forward contracts
- Reduce regulatory burden to manage local market power
- Important goal of standardized contract-based resource adequacy approach is to allow entities best able to manage supply risk, manage this risk
  - Avoid costly legal process at FERC and CPUC to obtain necessary generation capacity to meet demand under all possible future system conditions

Energy-Contracting Resource Adequacy Process

Transitioning to this approach to long-term resource adequacy requires significant advance notice

- First procurement of contracts should start delivery at least three years in advance

Retailers and generation owners need sufficient time to adapt to an energy-contracting resource adequacy process

Significantly more cross-hedging between resources to ensure system demand is met under all possible future system conditions

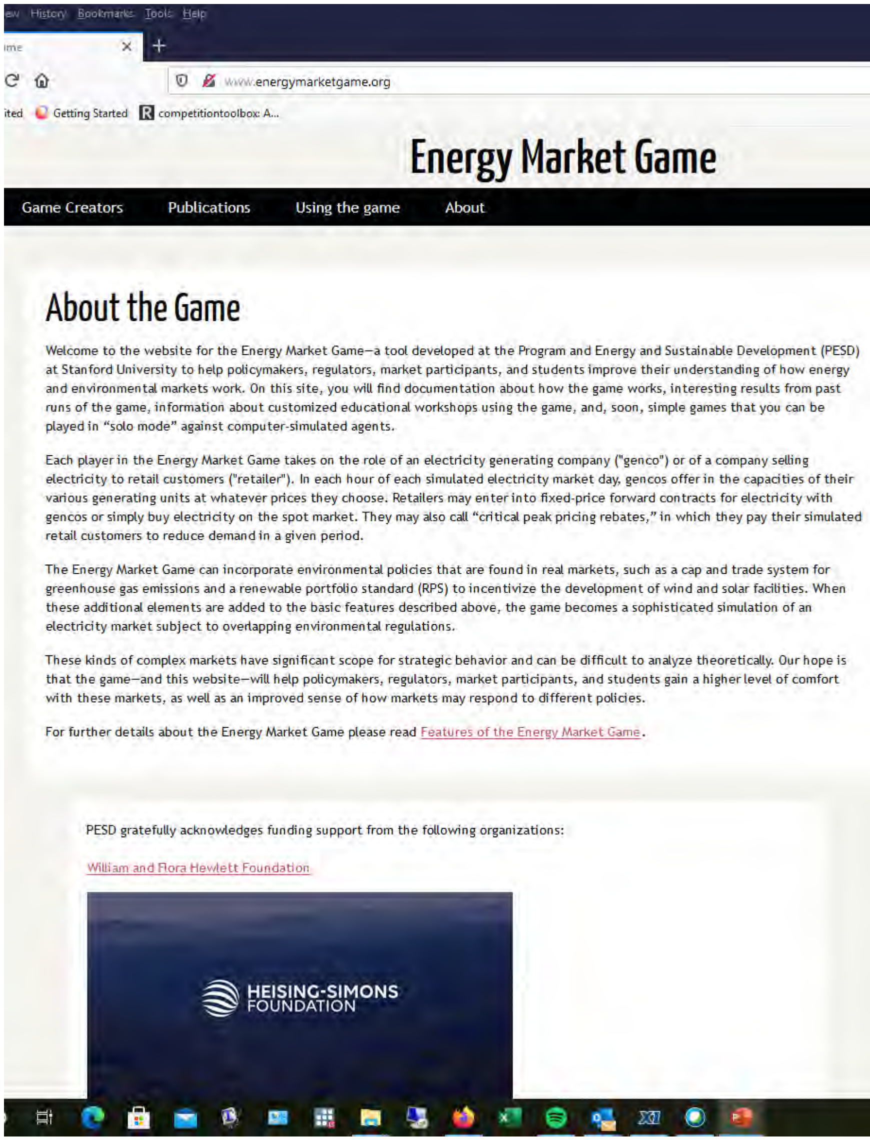
- Intermittent resources re-insurance with dispatchable resources
- Dispatchable resources earn premium for providing this insurance

Mechanism values a firm MWh more than a non-firm MWh

Bonus Topic:

Experimental Comparison of Capacity-Based versus Energy Contracting-Based Long-Term Resource Adequacy Mechanisms

Application to Long-Term Resource Adequacy



www.energymarketgame.org

Getting Started competitiontoolbox: A...

Energy Market Game

Game Creators Publications Using the game About

About the Game

Welcome to the website for the Energy Market Game—a tool developed at the Program and Energy and Sustainable Development (PESD) at Stanford University to help policymakers, regulators, market participants, and students improve their understanding of how energy and environmental markets work. On this site, you will find documentation about how the game works, interesting results from past runs of the game, information about customized educational workshops using the game, and, soon, simple games that you can be played in "solo mode" against computer-simulated agents.

Each player in the Energy Market Game takes on the role of an electricity generating company ("genco") or of a company selling electricity to retail customers ("retailer"). In each hour of each simulated electricity market day, gencos offer in the capacities of their various generating units at whatever prices they choose. Retailers may enter into fixed-price forward contracts for electricity with gencos or simply buy electricity on the spot market. They may also call "critical peak pricing rebates," in which they pay their simulated retail customers to reduce demand in a given period.

The Energy Market Game can incorporate environmental policies that are found in real markets, such as a cap and trade system for greenhouse gas emissions and a renewable portfolio standard (RPS) to incentivize the development of wind and solar facilities. When these additional elements are added to the basic features described above, the game becomes a sophisticated simulation of an electricity market subject to overlapping environmental regulations.

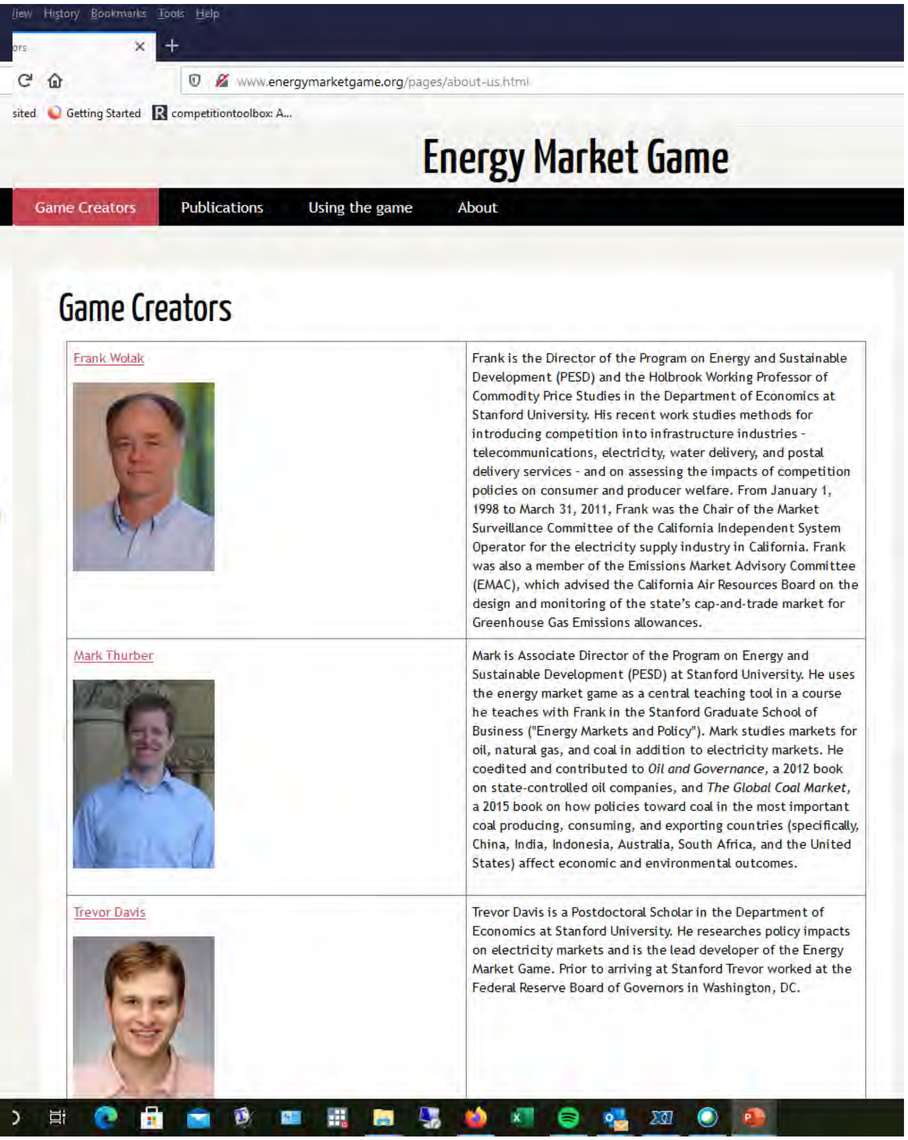
These kinds of complex markets have significant scope for strategic behavior and can be difficult to analyze theoretically. Our hope is that the game—and this website—will help policymakers, regulators, market participants, and students gain a higher level of comfort with these markets, as well as an improved sense of how markets may respond to different policies.

For further details about the Energy Market Game please read Features of the Energy Market Game.

PESD gratefully acknowledges funding support from the following organizations:

William and Flora Hewlett Foundation

HEISING-SIMONS FOUNDATION



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Game Creators

Frank Wolak	Frank is the Director of the Program on Energy and Sustainable Development (PESD) and the Holbrook Working Professor of Commodity Price Studies in the Department of Economics at Stanford University. His recent work studies methods for introducing competition into infrastructure industries - telecommunications, electricity, water delivery, and postal delivery services - and on assessing the impacts of competition policies on consumer and producer welfare. From January 1, 1998 to March 31, 2011, Frank was the Chair of the Market Surveillance Committee of the California Independent System Operator for the electricity supply industry in California. Frank was also a member of the Emissions Market Advisory Committee (EMAC), which advised the California Air Resources Board on the design and monitoring of the state's cap-and-trade market for Greenhouse Gas Emissions allowances.
Mark Thurber	Mark is Associate Director of the Program on Energy and Sustainable Development (PESD) at Stanford University. He uses the energy market game as a central teaching tool in a course he teaches with Frank in the Stanford Graduate School of Business ("Energy Markets and Policy"). Mark studies markets for oil, natural gas, and coal in addition to electricity markets. He coedited and contributed to *Oil and Governance*, a 2012 book on state-controlled oil companies, and *The Global Coal Market*, a 2015 book on how policies toward coal in the most important coal producing, consuming, and exporting countries (specifically, China, India, Indonesia, Australia, South Africa, and the United States) affect economic and environmental outcomes.
Trevor Davis	Trevor Davis is a Postdoctoral Scholar in the Department of Economics at Stanford University. He researches policy impacts on electricity markets and is the lead developer of the Energy Market Game. Prior to arriving at Stanford Trevor worked at the Federal Reserve Board of Governors in Washington, DC.

Application to Long-Term Resource Adequacy

Run capacity market versus energy contracting market experiment with Western US States regulators and members of staff of ANEEL, Brazilian Electricity Regulator (separately)

In each game players face identical demand and renewable energy realizations

- Only difference in games is long-term resource adequacy process

Capacity Market—Players compete to sell firm capacity equal to 110 percent of peak demand in a uniform price auction

Players given table of firm capacity, fixed cost, variable for each possible technology they can build

Players must construct at least the amount of firm capacity they won in capacity auction

Players required to meet 33% renewables portfolio standard

Players then compete to sell electricity in offer-based short term market

Energy Contracting Market—Players compete to sell long-term energy contracts tailored to daily load shape equal to 100 percent of expected demand in game

Players given same table of fixed cost and variable cost for each technology

Players were free to construct any mix of generation units to meet their forward contract obligations

Players required to meet 33% renewables portfolio standard

Players then compete to sell electricity in offer-based short-term market

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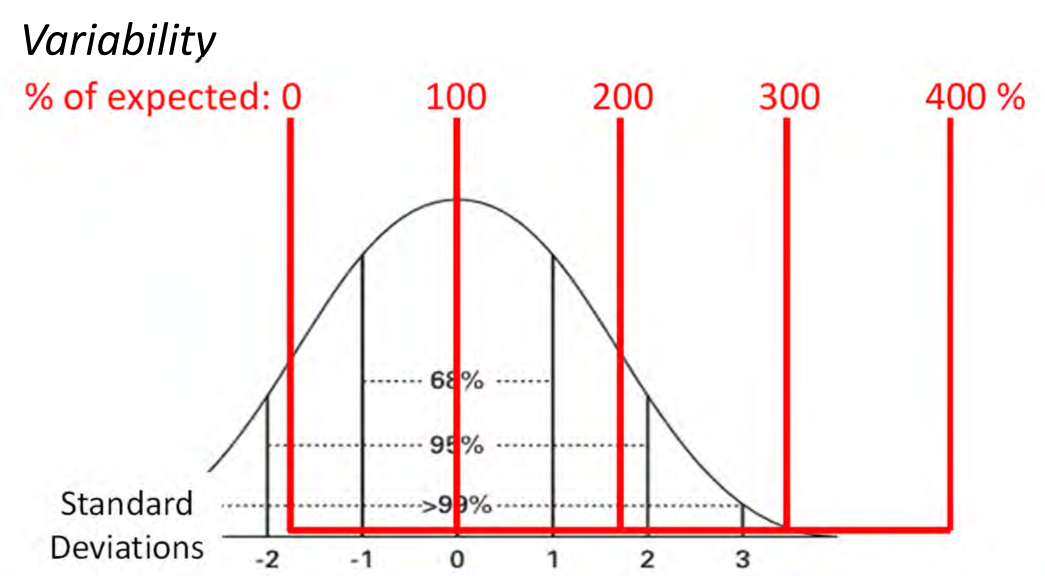
Variable Energy Resources

- Intermittent renewable generation units produce throughout day in similar pattern to actual pattern of production in California

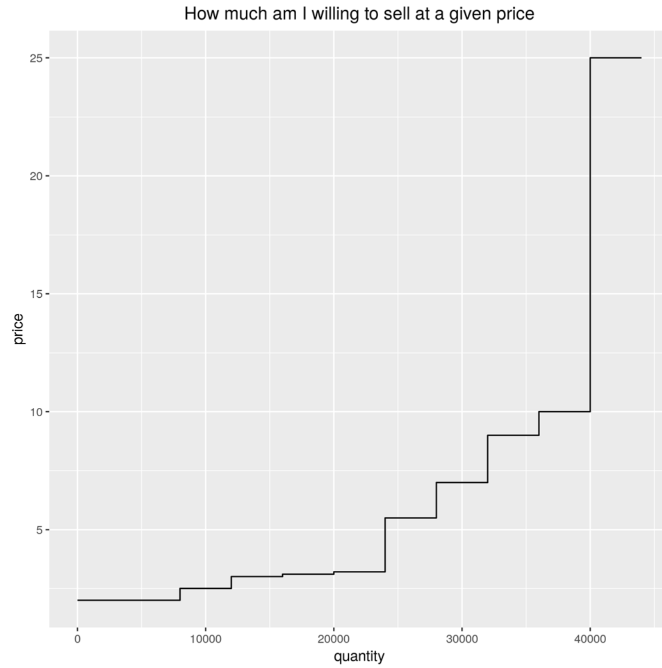
Type	Expected Generation (Normalized to Overall Average)				Variable Cost ($/MWh)
	4am	10am	4pm	10pm	
Wind	1.3	0.7	0.7	1.3	$0
Solar PV	0	2.0	2.0	0	$0



Renewable generation will fall between 40% and 160% of its “expected” value 68% of the time

Capacity Market game mechanics

1) Submit auction bids ($/MW-hr) for available capacity



- Minimum bid is $2/MW-hr (2/3 of fixed cost of Peak unit)
- Maximum bid is $25/MW-hr (full fixed cost of Base unit)
- Renewables counted at expected 4pm output
- Your existing capacity is bid in at minimum

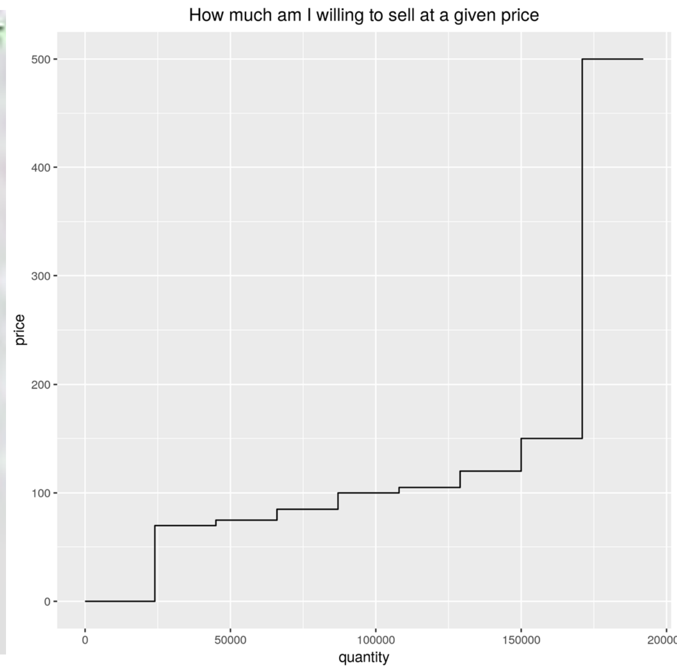
2) Buy/decommission units to meet capacity contracts you won (*required*)

Plant Type	Capacity (MW)	Var Cost ($/MWh)	Fixed cost ($/hr)	Fixed cost ($/MW-hr)	LCOE ($/MWh) -- by portion of hours running: 10%	25%	50%	75%	100%
Base	2000/1000	20	100,000/25,000	25	270	120	70	53	45
Intermediate	1000	45	10,000	10	145	85	65	58	55
Peak	1000	90	3,000	3	120	102	96	94	93

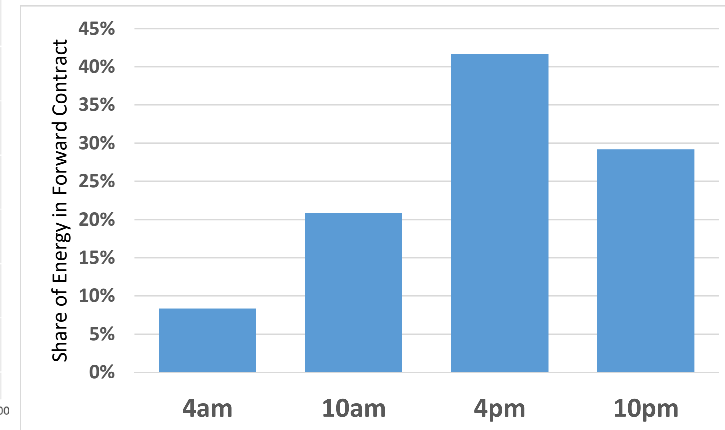
3) Bid in all thermal units to maximize returns

Forward Energy Contracting game mechanics

1) Submit auction bids ($/MWh) for available forward contracts (~100% of demand)



- Forward contracts have fixed load shape expected to meet demand



2) Buy/decommission units to physically hedge forward contracts you won

Plant Type	Capacity (MW)	Var Cost ($/MWh)	Fixed cost ($/hr)	Fixed cost ($/MW-hr)	LCOE ($/MWh) -- by portion of hours running: 10%	25%	50%	75%	100%
Base	2000/1000	20	100,000/25,000	25	270	120	70	53	45
Intermediate	1000	45	10,000	10	145	85	65	58	55
Peak	1000	90	3,000	3	120	102	96	94	93

- Renewables are not firm! (Can hedge if desired with more extra thermal capacity)

3) Bid in all thermal units to maximize returns. (Remember incentives w/contracts!)

Summary of Experiment Results

- For both games and both set of players—Western US regulators and ANEEL staff--computed average revenues paid by load and average cost to serve demand for game
- Capacity payment mechanism
  - Capacity payments, energy contracting and short-term energy market revenues divided by total demand served ($/MWh)
  - Total cost of serving demand divided by total demand ($/MWh)
- Energy contracting market
  - Energy contracting and short-term energy market revenues divided by total demand served ($/MWh)
  - Total cost of serving demand divided by total demand ($/MWh)
- For both Western US regulators and ANEEL staff average wholesale revenues per MWh from capacity mechanism was close to double that for energy contracting approach
  - Average cost to serve demand slightly lower for energy contracting approach

Concluding Comments

- Hard to find empirical evidence anywhere in the world of a well-performing capacity market
  - Even capacity market based on peak energy rent refunds in Colombia appears to reduce rather that improve market efficiency
- Standardized forward financial contracting approach appears to come closest to achieving market design goals in Singapore
  - Buy necessary energy far enough in advance of delivery to allow maximum flexibility of suppliers to meet these obligations at least cost and limit market power in spot market
  - Regulator must set portfolio standards for adequate hedging if maintain price and bid caps or shield final demand from short-term prices
- Head-to-head comparison of capacity market approach to energy contracting approach for two diverse groups—Western US regulators and staff of ANEEL yields same conclusions
  - Energy contracting is lower average cost per MWh, for consumers, approach
  - Lower average cost of production approach
- Contract adequacy approach can allow significant demand-side involvement as part of retailer's hedging strategy
  - With symmetric treatment of load and generation, individual loads can choose level of exposure to short-term price risk
  - Retailers can offer short-term price risk and mean price profiles and consumers choose which combination they prefer
  - Forward contracting is then tailored to hedge remaining fixed price retail obligations

Concluding Thought

There is nothing more difficult to take in hand, more perilous to conduct, or more uncertain in its success, than to take the lead in the introduction of a new order of things. Because the innovator has for enemies all those who have done well under the old conditions, and lukewarm defenders in those who may do well under the new."

– Niccolo Machiavelli (The Prince)

Thank you
Questions/Comments

Market Design in a Zero Marginal Cost Intermittent Renewable Future

by

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The basic features of an efficient short-term wholesale market design do not necessarily need to change to accommodate a significantly larger share of zero marginal cost intermittent renewable energy from wind and solar resources. A large share of controllable zero marginal cost generation does not create any additional market design challenge relative to a market with a large share of controllable positive marginal cost generation. Regardless of the technology, generation unit owners must recover their fixed costs from sales of energy, ancillary services, and long-term resource adequacy products.

A larger variance in the hourly amount of energy produced by intermittent resources is the primary market design challenge associated with a zero marginal cost renewable future. The past ten years in California have demonstrated that as the amount of wind and solar generation capacity increases, the variance in hourly energy produced by these resources increases. This increase in supply uncertainty also increases short-term price volatility, which can finance investments in storage and other technologies that allow consumers to shift their withdrawals of grid-supplied energy away from periods when little wind and solar energy is being produced.

An increased risk of large intermittent energy shortfalls and short-term price volatility implies a greater need for risk management activities. Greater short-term intermittent energy supply risk is likely to require accounting for more transmission and generation operating constraints in the day-ahead and real-time energy markets, as well as purchasing more operating reserves and creating additional ancillary service products. Because controllable generation units are likely to have to start and stop more frequently to make up for unexpected renewable energy shortfalls, there will be a greater need to develop short-term pricing approaches that recover the associated start-up and minimum load costs.

The potential for sustained periods of low intermittent energy production creates both a medium and long-term energy supply risk that requires a new long-term resource adequacy mechanism. The traditional capacity-based approach is unlikely to be the least cost mechanism for ensuring that future demand for energy is met. In a zero marginal cost intermittent future, wind and solar resources must hedge their energy supply risk with controllable generation resources in order to maintain long-term resource adequacy. Cross hedging between these technologies accomplishes two goals. First, it can provide the revenue stream necessary for fixed cost recovery by controllable generation units. Second, it ensures that there is sufficient controllable generation capacity to meet demand under all foreseeable future system states, with a high degree of confidence.

The remainder of this article first describes the key features of an efficient short-term wholesale market design: a multi-settlement locational marginal pricing (LMP) market with an automatic local market power mitigation (LMPM) mechanism, which is the standard market design for all short-term markets in the United States (US). This section concludes with a discussion of modifications of this basic design likely to be necessary to accommodate a larger share of intermittent renewables.

The second half of the paper describes a new long-term resource adequacy mechanism for the efficient short-term market design for an electricity supply industry with a large share of zero marginal cost intermittent renewables. I first explain why a wholesale electricity market requires a long-term resource adequacy mechanism. I then describe a mandated standardized long-term contract approach to long-term resource adequacy that provides strong incentives for intermittent renewable resource owners to hedge their energy supply risk with controllable generation resource owners. I argue that this mechanism ensures long-term resource adequacy at a reasonable cost for final consumers while also allowing the short-term wholesale price volatility that can finance investments in storage and other load-shifting technologies necessary to manage a large share of intermittent renewable resources.

1. Short-Term Market Design

More than twenty-five years of international experience with wholesale electricity market design has identified four crucial features of an efficient short-term market design. First is the extent to which the market mechanism used to set dispatch levels and locational prices is consistent with how the grid and generation units actually operate. Second is a financially binding day-ahead market that prices all transmission and generation unit operating constraints expected to be relevant in real-time. Third is an automatic LMPM mechanism that limits the ability of a supplier to influence the price it receives when it possesses a substantial ability to exercise market power. Fourth are retail market policies that foster active participation of final demand in the wholesale market.

The early US wholesale market designs in the PJM Interconnection, ISO New England, California, and Texas employed simplified versions of the transmission network configuration and generation unit operating constraints. Similar market designs currently exist throughout Europe and the rest of the world. They set a single market-clearing price for an hour or half-hour for an entire control area or for large geographic regions, despite the fact that in real-time there are often generation units with offer prices below this market-clearing price not producing electricity and units with offer prices above this market-clearing price producing electricity. This outcome occurs because of the location of demand and available generation units within the region, and the configuration of the transmission network prevents some of these low-offer-price units from producing electricity and requires some of the high-offer-price units to supply electricity.

This approach to short-term market design provides incentives for suppliers to take actions to exploit the fact that " in real-time physics wins," rather than offer their resources into the day-ahead market in a manner that minimizes the cost of meeting demand at all locations in the grid in real-time. Instead, suppliers take actions in the simplified day-ahead market that allow them to profit from knowing they will be needed (or not needed) in real-time because of transmission and generation unit operating constraints.

1.1. Locational Marginal Pricing

Starting with PJM in 1998 and ending with Texas in late 2010, all US wholesale markets adopted a multi-settlement locational marginal pricing (LMP) market design that co-optimizes the procurement of energy and ancillary services and includes an automatic local market power mitigation mechanism built into the market software. This design has a day-ahead financial market which satisfies the locational demands for energy and each ancillary service simultaneously for all 24 hours of the following day. A real-time market then operates using the same network model as the day-ahead market adjusted to real-time system conditions. Deviations from purchases and sales in the day-ahead market are cleared using these real-time prices. Both of these markets price all relevant transmission network and other relevant operating constraints on generation units. As I discuss below, this market design can foster active participation of final demand in the wholesale market.

Only generation unit output levels that are physically feasible will be accepted in both the day-ahead and real-time markets. Prices for the same hour vary depending on whether the location is in a generation-deficient or generation-rich region of the transmission network. The locational marginal price or nodal price at a given location is the increase in the minimized value of the "as-offered costs" of serving the locational demands for energy and all ancillary services as a result of a one-unit increase in the amount of energy withdrawn at that location in the transmission network. The price of each ancillary service is equal to the increase in the optimized value of the objective function as a result of a one-unit increase in the demand for that ancillary service.

The recent experience of many European countries with significant wind and solar resources indicates that the cost of making the final schedules that emerge from their zonal markets physically feasible is likely to get even larger as the amount of intermittent renewable generation capacity increases. According to the European Network of Transmission System Operators for Electricity, in 2017 these costs were over 1 billion euros in Germany, more than 400 million euros in Great Britain, over 80 million euros in Spain, and approximately 50 million euros in Italy.

1.2. Multi-Settlement LMP Market

A multi-settlement LMP market has at least a day-ahead forward market and a real-time market, each of which employs the same market-clearing mechanism. The day-ahead market typically allows generation unit owners to submit three-part offers to supply energy: start-up costs, minimum load costs, and an energy offer curve. These are used to compute hourly generation schedules and ancillary service quantities and LMPs for energy and ancillary services for all 24 hours of the following day. A generation unit will not be accepted to supply energy in the day-ahead market unless the combination of its offered start-up costs, minimum load costs and energy production costs are part of the least as-offered-cost solution to serving the hourly locational demands for all 24 hours of the following day.

The energy schedules that emerge from the day-ahead market do not require a generation unit to produce the energy sold or a load to consume the energy purchased in the day-ahead market at a given location. Any production shortfall relative to a day-ahead generation schedule must be purchased from the real-time market at that location. Any production greater than a generation unit's day-ahead schedule is sold at the real-time price at that location. Any additional consumption beyond a load's day-ahead energy schedule is paid for at the real-time price at that location, and the surplus of a day-ahead schedule relative to actual consumption is sold at the real-time price at that location.

1.3. Mitigating Local Market Power

The configuration of the transmission network, the level and location of demand, as well as the level of output of other generation units can create system conditions in which almost any generation unit or group of generation units has a significant ability to exercise unilateral market power. The constrained-on generation problem is an example of this phenomenon. The unit's owner knows that it must be accepted to supply energy regardless of its offer price. Without an LMPM mechanism, there may be no limit to the offer price the unit's owner could submit and be accepted to supply energy. During the first summer of the California market, when there was no formal LMPM mechanism, suppliers submitted extremely high offers for energy and ancillary services when these system conditions arose.

This logic is why market power mitigation mechanisms typically used in Europe and other industrialized regions and initially employed in the US, that designate in advance the offers of certain generation units for mitigation for an entire year, miss many instances of the exercise of substantial unilateral market power.

An automated LMPM mechanism built into the market software that relies on actual system conditions to determine whether any supplier has a substantial ability and incentive to exercise unilateral market power is likely to be significantly more effective. This regulator-approved administrative procedure determines: (1) when a supplier has an ability to exercise local market power worthy of mitigation, (2) the value of the supplier's mitigated offer price, and (3) the price the mitigated supplier is paid. It is increasingly clear to regulators around the world, particularly those that operate markets with a finite amount of transmission capacity and significant intermittent renewable generation capacity, that an automatic LMPM mechanism is a necessary feature of any short-term market design.

Because these LMPM mechanisms are built into the market software of all US markets and automatically mitigate the offers of suppliers deemed to have substantial ability to exercise unilateral market power, they are effective at preventing the exercise of significant local market power with little disruption to the operation of the short-term market.

1.4. Benefits of a Multi-Settlement LMP Market

A multi-settlement LMP market design can facilitate the active participation of final consumers in the wholesale market and reduce both the input fuel and total variable cost of producing the same amount of thermal energy relative to a multi-settlement zonal market design. The presence of an automatic LMPM mechanism and make-whole payments that guarantee start-up, minimum load, and energy cost recovery for the day for all generation units committed to operate in the day-ahead market reduces the incentive for suppliers to exercise unilateral market power. An expected profit-maximizing supplier with no ability to exercise unilateral market power will submit an offer price equal to its marginal cost because make-whole payments ensure recovery of their start-up, minimum load, and energy costs.

Because day-ahead purchases are firm financial commitments, a retailer can sell energy purchased in the day-ahead market at the real-time price by consuming less than its day-ahead energy schedule. This eliminates the need for the regulator to set an administrative baseline relative to which a retailer sells demand reductions. The day-ahead market also allows retailers and large consumers to submit price-sensitive bid curves into the day-ahead market to reduce the market-clearing price and the quantity of energy they purchase in the day-ahead market.

1.5. Modifications for Large Scale Intermittent Renewables Deployment

A multi-settlement LMP market design is capable of managing a generation mix with a significant share of intermittent renewables. However, some modifications are likely to be needed as the share of intermittent renewable resources increases. Additional operating constraints will need to be incorporated into the day-ahead and real-time market models for reliable system operation with an increased quantity of intermittent renewables.

There is also likely to be a need to introduce additional ancillary services to accommodate a larger share of intermittent renewable energy. For example, California introduced a fast-ramping ancillary service product that compensates controllable generation units for not supplying energy during certain hours of the day in order to have sufficient unloaded capacity to meet the rapid increase in net demand (the difference between system demand and renewable generation) in the early evening when the state's solar resources stop producing.

Because controllable resources are likely to have to start and stop more frequently as the share of intermittent resources increases, implementations of convex hull pricing and other market-clearing mechanisms that limit the magnitude of make-whole payments will need to be developed.

2. Resource Adequacy with Significant Intermittent Renewables

Why do wholesale electricity markets require a regulatory mandate to ensure long-term resource adequacy? Electricity is essential to modern life, but so are many other goods and services. Consumers want cars, but there is no regulatory mandate that ensures enough automobile assembly plants to produce these cars. They want point-to-point air travel, but there is no regulatory mandate to ensure enough airplanes to accomplish this. Many goods are produced using high fixed cost, low marginal cost technologies, similar to electricity supply. Nevertheless, these firms recover their cost of production, including a return on the capital invested, by selling their output at a market-determined price.

So, what is different about electricity that requires a long-term resource adequacy mechanism? The regulatory history of the electricity supply industry and the legacy technology for metering electricity consumption results in what I call a *reliability externality*.

2.1. The Reliability Externality

Different from the case of wholesale electricity, in the market for automobiles and air travel there is no regulatory prohibition on the short-term price rising to the level necessary to clear the market. Airlines adjust the prices for seats on a flight over time in an attempt to ensure that the number of customers traveling on that flight equals the number of seats flying. This ability to use price to allocate the available seats is also what allows the airline to recover its total production costs.

Using the short-term price to manage the real-time supply and demand balance in a wholesale electricity market is limited by a finite upper bound on a supplier's offer price and/or a price cap that limits the maximum market-clearing price. Although offer caps and price caps can limit the ability of suppliers to exercise unilateral market power in the short-term energy market, they also reduce the revenues suppliers can receive during scarcity conditions. This is often referred to as the *missing money* problem for generation unit owners. However, this missing money problem is only a symptom of the existence of the "reliability externality."

This externality exists because offer caps limit the cost to electricity retailers of failing to hedge their purchases from the short-term market. Specifically, if the retailer or large consumer knows the price cap on the short-term market is $250/MWh, then it is unlikely to be willing to pay more than that for electricity in any earlier forward market. This creates the possibility that real-time system conditions can occur where the amount of electricity demanded at or below the offer cap is less than the amount suppliers are willing to offer at or below the offer cap. This outcome implies that the system operator must be forced to either abandon the market mechanism or curtail load until the available supply offered at or below the offer cap equals the reduced level of demand, as occurred a number of times in California between January 2001 and April 2001, and most recently on August 14 and 15, 2020.

Because random curtailments of supply—also known as rolling blackouts—are used to make demand equal to the available supply at or below the offer cap under these system conditions, this mechanism creates a "reliability externality" because no retailer bears the full cost of failing to procure adequate amounts of energy in advance of delivery. A retailer that has purchased sufficient supply in the forward market to meet its actual demand is equally likely to be randomly curtailed as another retailer of the same size that has not procured adequate energy in the forward market. For this reason, all retailers have an incentive to under-procure their expected energy needs in the forward market.

The lower the offer cap, the greater is the likelihood that the retailer will delay their electricity purchases to the short-term market. Delaying more purchases to the short-term market increases the likelihood of insufficient supply in the short-term market at or below the offer cap. Because retailers do not bear the full cost of failing to procure sufficient energy in the forward market to meet their future demand, there is a missing market for long-term contracts for long enough delivery horizons into the future to allow new generation units to be financed and constructed to serve demand under all future conditions in the short-term market. Therefore, a regulator-mandated long-term resource adequacy mechanism is necessary to replace this missing market.

Some form of regulatory intervention is necessary to internalize the resulting reliability externality, unless the regulator is willing to eliminate or substantially increase the offer cap so that the short-term price can be used to equate available supply to demand under all possible future system conditions. This approach is taken by the Electricity Reliability Council of Texas (ERCOT), which has a $9,000/MWh offer cap, and National Electricity Market in Australia, which has a 15,000 Australia Dollars per MWh offer cap. If customers do not have interval meters that can record their consumption on an hourly basis, then they have a very limited ability to benefit from shifting their consumption away from high-priced hours. All that can recorded for these customers is their total consumption between two successive meter readings so they can only be billed based on an average wholesale price during the billing cycle. Therefore, raising or having no offer cap on the short-term market would not be advisable in a region where few customers have interval meters. Even in regions with interval meters, there would be substantial political backlash from charging hourly wholesale prices that cause real-time demand to equal available supply under all possible future system conditions.

Currently, the most popular approach to addressing this reliability externality is a capacity payment mechanism that assigns a firm capacity value to each generation unit based on the amount of energy it can provide under stressed system conditions. Sufficient firm capacity procurement obligations are then assigned to retailers to ensure that annual system demand peaks can be met.

Capacity-based approaches to long-term resource adequacy rely on the credibility of the firm capacity measures assigned to generation units. This is a relatively straightforward process for thermal units. The nameplate capacity of the generation unit times its annual availability factor is a reasonable estimate of the amount of energy the unit can provide under stressed system conditions. For the case of hydroelectric facilities, this process is less straightforward. The typical approach uses percentiles of the distribution of past hydrological conditions for that generation unit to determine its firm capacity value.

Assigning a firm capacity value to a wind or solar generation unit is extremely challenging for several reasons. First, these units only produce when the underlying resource is available. If stressed system conditions occur when the sun is not shining or the wind is not blowing, these units should be assigned little, if any, firm capacity value. Second, because there is a high degree of contemporaneous correlation between the energy produced by solar and wind facilities within the same region, the usual approach to determining the firm capacity of a wind or solar unit assigns a smaller value to that unit as the total MWs of wind or solar capacity in the region increases. These facts imply that a capacity-based long-term resource adequacy mechanism is poorly suited to a zero marginal cost intermittent renewable feature.

2.2. Supplier Incentives with Fixed-Price Forward Contract Obligations for Energy

The standardized fixed-price forward contract (SFPFC) approach to long-term resource adequacy recognizes that a supplier with the ability to serve demand at a reasonable price may not do so if it has the ability to exercise unilateral market power. A supplier with the ability to exercise unilateral market power with a fixed-price forward contract obligation finds it expected profit maximizing to minimize the cost of supplying this forward contract quantity of energy. The SFPFC long-term resource adequacy mechanism takes advantage of this incentive by requiring retailers to hold hourly fixed-price forward contract obligations for energy that sum to the hourly value of system demand. This implies that all suppliers find it expected profit maximizing to minimize the cost of meeting their hourly fixed-price forward contract obligations, the sum of which equals the hourly system demand for all hours of the year.

To understand the logic behind the SFPFC mechanism, consider the example of a supplier that owns 150 MWs generation capacity that has sold 100 MWh in a fixed-forward contract at a price of $25/MWh for a certain hour of the day. This supplier has two options for fulfilling this forward contract: (1) produce the 100 MWh energy from its own units at their marginal cost of

$20/MWh or (2) buy this energy from the short-term market at the prevailing market-clearing price. The supplier will receive $2,500 from the buyer of the contract for the 100 MWh sold, regardless of how it is supplied. This means that the supplier maximizes the profits it earns from this fixed-price forward contract sale by minimizing the cost of supplying the 100 MWh of energy.

To ensure that the least-cost "make versus buy" decision for this 100 MWh is made, the supplier should offer 100 MWh in the short-term market at its marginal cost of $20/MWh. This offer price for 100 MWh ensures that if it is cheaper to produce the energy from its generation units—the market price is at or above $20/MWh—the supplier's offer to produce the energy will be accepted in the short-term market. If it is cheaper to purchase the energy from the short-term market—the market price is below $20/MW—the supplier's offer will not be accepted and the supplier will purchase the 100 MWh from the short-term market at a price below $20/MWh.

This example demonstrates that the SFPFC approach to long-term resource adequacy makes it expected profit-maximizing for each seller to minimize the cost supplying the quantity of energy sold in this forward contract each hour of the delivery period. By the logic of the above example, each supplier will find it in its unilateral interest to submit an offer price into the short-term market equal to its marginal cost for its hourly SFPFC quantity of energy, in order to make the efficient "make versus buy" decision for fulfilling this obligation.

In addition, because all suppliers know that the sum of the values of the hourly SFPFC obligations for all suppliers is equal the system demand, each firm knows that its competitors have substantial fixed-price forward contract obligations for that hour. This implies that all suppliers know that they have limited opportunities to raise the price they receive for short-term market sales beyond their hourly SFPFC quantity. For the above example, the supplier that owns 150 MWs of generation capacity has a strong incentive to submit an offer price close to its marginal cost to supply any energy beyond the 100 MWh of SFPFC energy it is capable of producing. Therefore, attempts by any supplier to raise prices in the short-term market by withholding output beyond their SFPFC quantity are likely to be unsuccessful because of the aggressiveness of the offers into the short-term market by its competitors with hourly SFPFC obligations.

2.3. SFPFC Approach to Resource Adequacy

This long-term resource adequacy mechanism requires all electricity retailers to hold SFPFCs for energy for fractions of realized system demand at various horizons to delivery. For example, retailers in total must hold SFPFCs that cover 100 percent of realized system demand, 95 percent of realized system demand one year in advance of delivery, 90 percent two-years in advance of delivery, 87 percent three years in advance of delivery, and 85 percent four years in advance of delivery. The fractions of system demand and number of years in advance that the SFPFCs must be purchased are parameters set by the regulator to ensure long-term resource adequacy. In the case of a multi-settlement LMP market, the SFPFCs would clear against the quantity-weighted average of the hourly locational prices at all load withdrawal nodes.

SFPFCs are shaped to the hourly system demand within the delivery period of the contract. Figure 1 contains a sample pattern of system demand for a four-hour delivery horizon. The total demand for the four hours is 1000 MWh, and the four hourly demands are 100 MWh, 200 MWh, 400 MWh and 300 MWh. Therefore, a supplier that sells 300 MWh of SFPFC energy has the hourly system demand-shaped forward contract obligations of 30 MWh in hour 1, 60 MWh in hour 2, 120 MWh in hour 3 and 90 MWh in hour 4 for Firm 1 in Figure 2. The hourly forward contract obligations for Firm 2 that sold 200 MWh SFPFC energy and Firm 3 that sold 500 MWh of SFPFC energy are also shown in Figure 2. These SFPFC obligations are also allocated across the four hours according to the same four hourly shares of total system demand. This ensures that the sum of the hourly values of the forward contract obligations for the three suppliers is equal to the hourly value of system demand. Taking the example of hour 3, Firm 1's obligation is 120 MWh, Firm 2's is 80 MWh and Firm 3's is 200 MWh. These three values sum to 400 MWh, which is equal to the value of system demand in hour 3 shown in Figure 1.

These standardized fixed-price forward contracts are allocated to retailers based on their share of system demand during the month. Suppose that the four retailers in Figure 3 consume 1/10, 2/10, 3/10, and 4/10, respectively, of the total energy consumed during the month. This means that Retailer 1 is allocated 100 MWh of the 1000 MWh SFPFC obligations for the four hours, Retailer 2 is allocated 200 MWh, Retailer 3 is allocated 300 MWh, and Retailer 4 is allocated 400 MWh. The obligations of each retailer are then allocated to the individual hours using the same hourly system demand shares used to allocate the SFPFC energy sales of suppliers to the four hours. This allocation process implies Retailer 1 holds 10 MWh in hour 1, 20 MWh in hours 2, 40 MWh in hour 3 and 30 MWh in hour 4. Repeating this same allocation process for the other three retailers yields the remaining three hourly allocations shown in Figure 3. Similar to the case of the suppliers, the sum of allocations across the four retailers for each hour equals the total hourly system demand. For period 3, Retailer 1's holding is 40 MWh, Retailer 2's is 80 MWh, Retailer 3's is 120 MWh, and Retailer 4's is 160 MWh. The sum of these four magnitudes is equal to 400 MWh, which is the system demand in hour 3.

2.4. Mechanics of Standardized Forward Contract Procurement Process

The SFPFCs would be purchased through auctions several years in advance of delivery in order to allow new entrants to compete to supply this energy. Because the aggregate hourly values of these SFPFC obligations are allocated to retailers based on their actual share of system demand during the month, this mechanism can easily accommodate retail competition. If one retailer loses load and another gains it during the month, the share of the aggregate hourly value of SFPFCs allocated to the first retailer falls and the share allocated to the second retailer rises.

The wholesale market operator would run the auctions with oversight by the regulator. One advantage of the design of the SFPFC products is that a simple auction mechanism can be used to purchase each annual product. A multi-round auction could be run where suppliers submit the total amount of annual SFPFC energy they would like to sell for a given delivery period at the price for the current round. Each round of the auction the price would decrease until the amount suppliers are willing to sell at that price is less than or equal to the aggregate amount of SFPFC energy demanded.

The wholesale market operator would also run a clearinghouse to manage the counterparty risk associated with these contracts. All US wholesale market operators currently do this for all participants in their energy and ancillary services markets. In several US markets, the market operator also provides counterparty risk management services for long-term financial transmission rights, which is not significantly different from performing this function for SFPFCs.

SFPFCs auctions would be run on an annual basis for deliveries starting two, three, and four years in the future. In steady state, auctions for incremental amounts of each annual contract would also be needed so that the aggregate share of demand covered by each annual SFPFC could increase over time. The eventual 100 percent coverage of demand occurs through a final true-up auction that takes place after the realized values for hourly demand for the delivery period are known.

Consider the following two examples of how the true-up auction would work. Assume for simplicity, the monthly load shares of the four retailers remain unchanged. Suppose that the initial 1000 MWh SFPFC in the above example sold at $50/MWh. However, suppose that actual demand turned out to be 10 percent higher in every period as shown Figure 4 and the additional 100 MWh purchased in the true-up auction sold at $80/MWh. If each firm sold 10 percent more SFPFC energy in the true-up auction this would yield the hourly obligations for each supplier shown in Figure 5. The hourly obligations for the four retailers are shown in Figure 6. These would clear against the average cost of purchases from the original auction and true-up auction of $52.73. If the realized hourly demands are ten percent lower as shown in Figure 7, the true-up auction would buy back 100 MWh of SFPFC energy. If all suppliers bought back 10 percent of their initial sales at $20/MWh, the resulting hourly obligations would be those shown in Figure 8. The 10 percent smaller hourly obligations of the four retailers are shown in Figure 9 and these would clear against the average cost of the initial auction purchase less the revenues from the true-up auction sales for the required 900 MWh of obligations of $53.33.

As shown in Figures 6 and 9, each purchase or sale of the same annual SFPFC product is allocated to retailers according to their load shares during the delivery month. If three different size purchases are made for the same annual SFPFC product at different prices, then each retailer is allocated its load share for the month of these three purchases. This ensures a level playing field for retailers with respect to their long-term resource adequacy obligation. All retailers face the same average price for the long-term resource adequacy obligation associated with their realized demand for the month.

The advance purchase fractions of the final demand are the regulator's security blanket to ensure that system demands can be met for all hours of the year for all possible future system conditions. If the regulator is worried that not enough resources will be available in time to satisfy this requirement, it can increase the share of final demand that it purchases in each annual SFPFC auction. As shown above, if too much SFPFC energy is purchased in an annual auction, it can be sold back to generation unit owners in a later auction or the final true-up auction.

Cross hedging between controllable generation units and intermittent renewable resources under this mechanism is enforced by tying the amount of SFPFC energy a generation unit owner can sell on an annual basis to the value of their firm energy. The system operator would assign firm energy values for each generation unit using a mechanism similar to what is currently used to compute firm capacity values. Multiplying a unit's MWs of firm capacity by the number of hours in the year would yield the unit's firm energy value, which is the upper bound on the amount of SFPFC energy the unit owner could sell in all auctions for an annual compliance period. Because the firm capacity of a generation unit is defined as the amount of energy it can produce under stressed system conditions, this limitation on annual sales of firm energy implies that intermittent wind and solar resources would sell much less SFPFC energy than the total MWhs they expect to produce in a typical year, and controllable generation unit owners would sell significantly more SFPFC energy than the total MWhs they expect to produce in an typical year.

In most years, a controllable resource owner would be producing energy in a small number of hours of the year, but earning the difference between the price at which they sold the energy in the SFPFC auction and the hourly short-term market price times the hourly value of its SFPFC energy obligation for all the hours that it does not produce energy. Intermittent renewables owners would typically produce more than their SFPFC obligation in energy and sell the additional energy at the short-term price. In years with low renewable output near their SFPRC obligations, controllable resource owners would produce close to the hourly value of their SFPFC energy obligation, thus making average short-term prices significantly higher. However, aggregate retail demand would be shielded from these high short-term prices because of their SFPC holdings.

2.4. Advantages of SFPFC Approach to Long-Term Resource Adequacy

This mechanism has a number of advantages relative to a capacity-based approach. There is no regulator-mandated aggregate capacity requirement. Generation unit owners are allowed to decide both the total MWs and the mix of technologies to meet their SFPFC energy obligations. There is also no prohibition on generation unit owners or retailers engaging in other hedging arrangements outside of this mechanism. Specifically, a retailer could enter into a bilateral contract for energy with a generation unit owner or other retailer to manage the short-term price and quantity risk associated with the difference between their actual hourly load shape and the hourly values of their retail load obligation. This mechanism provides a nudge to market participants to develop a liquid market for these bilateral contract arrangements at horizons to delivery similar to the SFPFC products. Instead of starting from the baseline of no fixed-price forward contract coverage of system demand by retailers, this mechanism starts with 100 percent coverage of system demand, which retailers can unwind at their own risk.

For the regulated retail customers, the purchase prices of SFPFCs can be used to set the wholesale price implicit in the regulated retail price over the time horizon that the forward contract clears. This would provide retailers with a strong incentive to reduce their average wholesale energy procurement costs below this price through bilateral hedging arrangements, storage investments, or demand response efforts.

There are several reasons why this mechanism should be a more cost-effective approach to long-term resource adequacy than a capacity-based mechanism in a zero marginal cost intermittent future. First, the sale of SFPFC energy starting delivery two or more years in the future provides a revenue stream that will significantly increase investor confidence in recovering the cost of any investment in new generation capacity.

Second, because retailers are protected from high short-term prices by total hourly SFPFC holdings equal to system demand, the offer cap on the short-term market can be raised in order to increase the incentive for all suppliers to produce as much energy as possible during stressed system conditions. Third, the possibility of higher short-term price spikes can finance investments in storage and load-shifting technologies and encourage active participation of final demand in the wholesale market, further enhancing system reliability in a market with significant intermittent renewable resources.

If SFPFC energy is sold for delivery in four years based on a proposed generation unit, the regulator should require construction of the new unit to begin within a pre-specified number of months after the signing date of the contract or require posting of a substantially larger amount of collateral in the clearinghouse with the market operator. Otherwise, the amount of SFPFC energy that this proposed unit sold would be automatically liquidated in a subsequent SFPFC auction and a financial penalty would be imposed on the developer. Other completion milestones would have to be met at future dates to ensure the unit is able to provide the amount of firm energy that it committed to provide in the SFPFC contract sold. If any of these milestones were not met, the contract would be liquidated.

3. Final Comments

There is no perfect wholesale market design. There are only better wholesale market designs, and what constitutes a better design depends on many factors specific to the region. The long-term resource adequacy mechanism should be coordinated with the short-term market design. Although there is general agreement on the key features of a best-practice short-term market design, many details must be adjusted to reflect local conditions. For this reason, wholesale market design is a process of continuous learning, adaption, and hopefully, improvement. The standardized energy contracting approach to long-term resource adequacy described in this paper is an example of this process. While it has a number of features that are likely make it significantly better suited to a zero-marginal-cost intermittent-renewables-electricity-supply industry, there are many details of this basic mechanism that should be adapted to reflect local conditions.

Further Reading

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Biography

Frank A. Wolak is with Stanford University

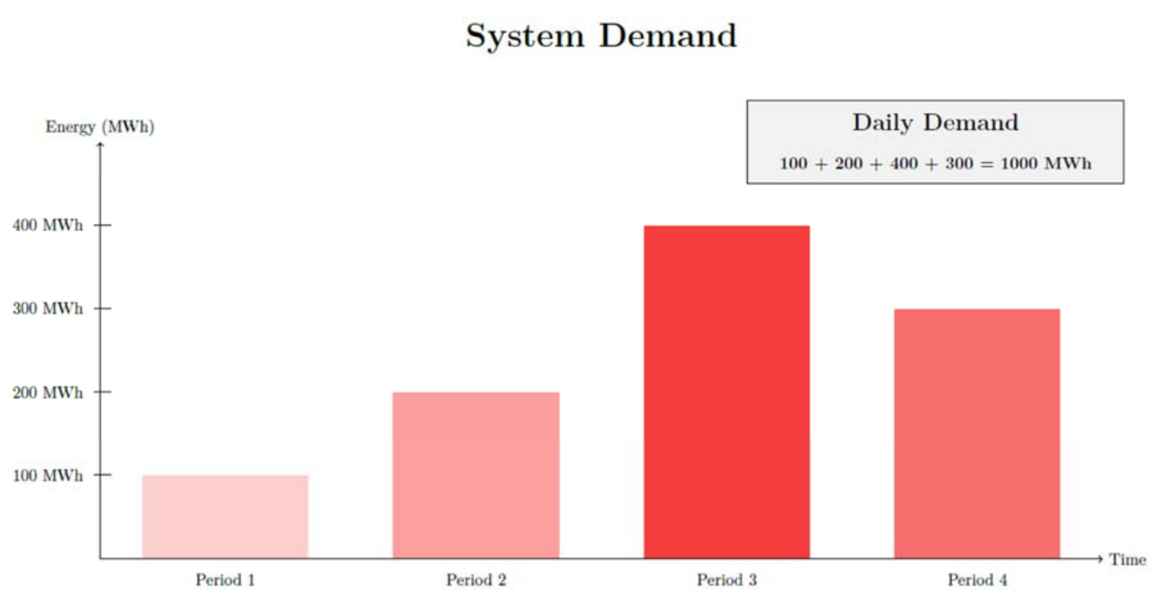

Figure 1: Hourly System Demands

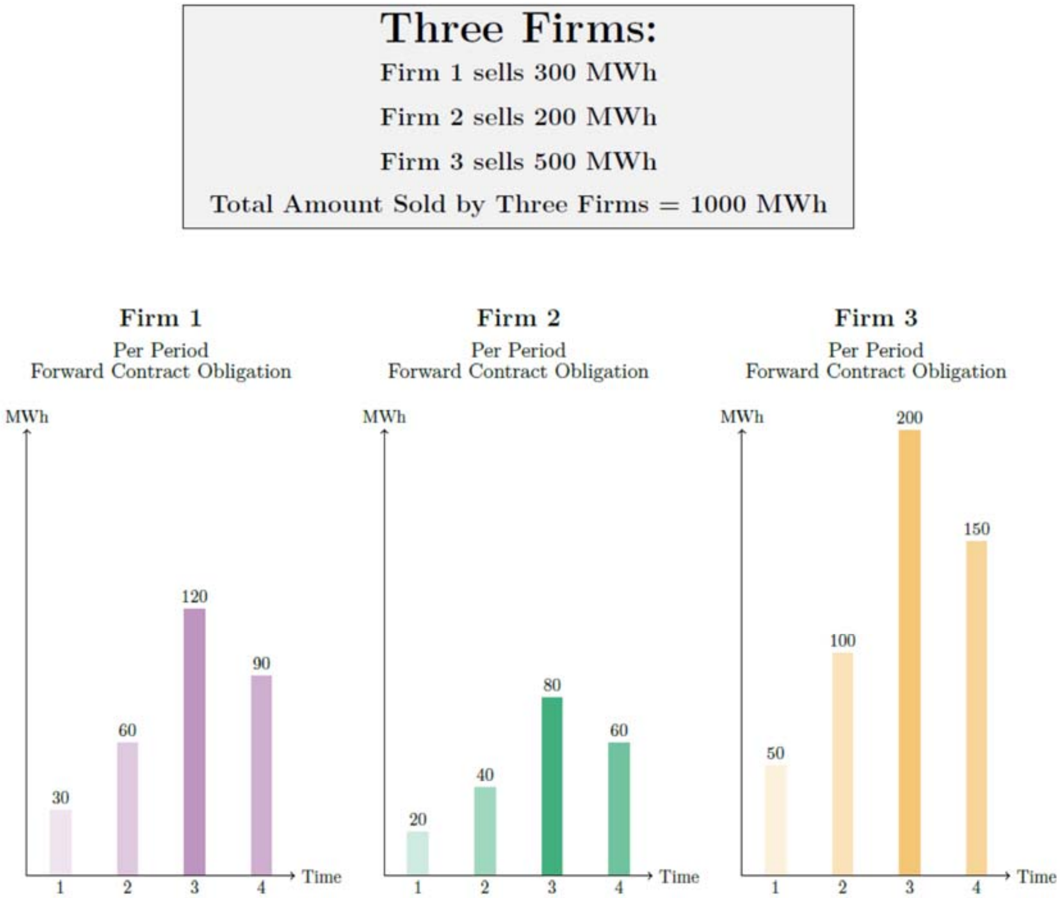

Figure 2: Hourly Forward Contract Quantities for Three Suppliers

Four Retailers:

Retailer 1 holds 100 MWh

Retailer 2 holds 200 MWh

Retailer 3 holds 300 MWh

Retailer 4 holds 400 MWh

Total Amount Held by Four Retailers = 1000 MWh

Figure 3: Hourly Forward Contract Quantities for Four Retailers

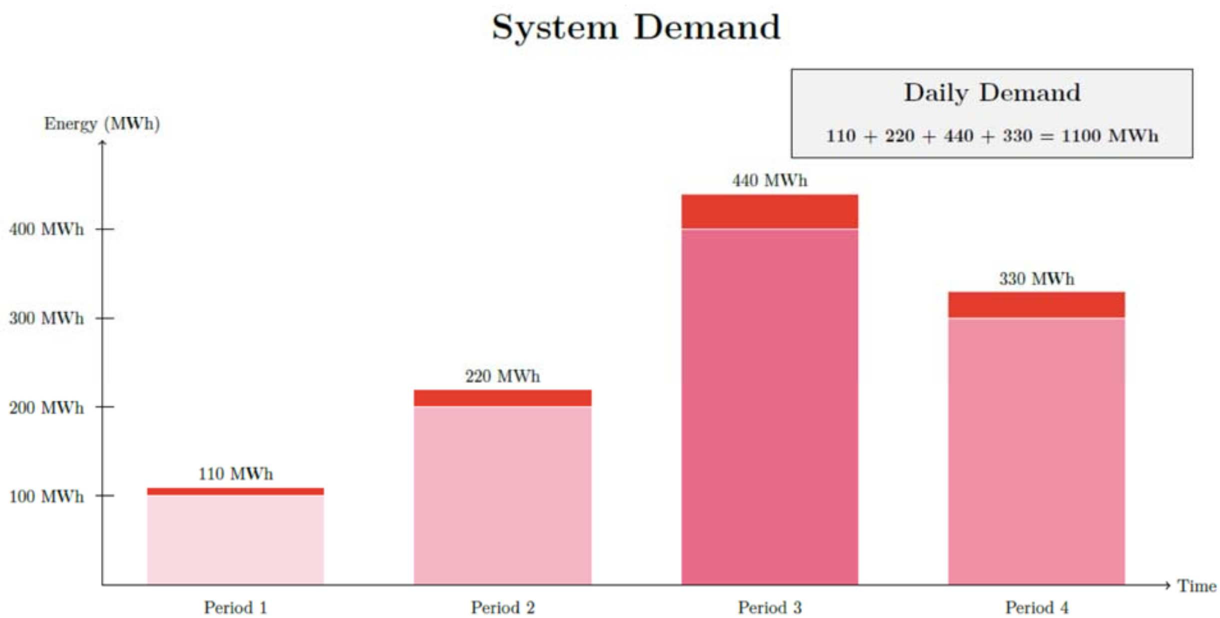

Figure 4: Hourly System Demands (10 Percent Higher)

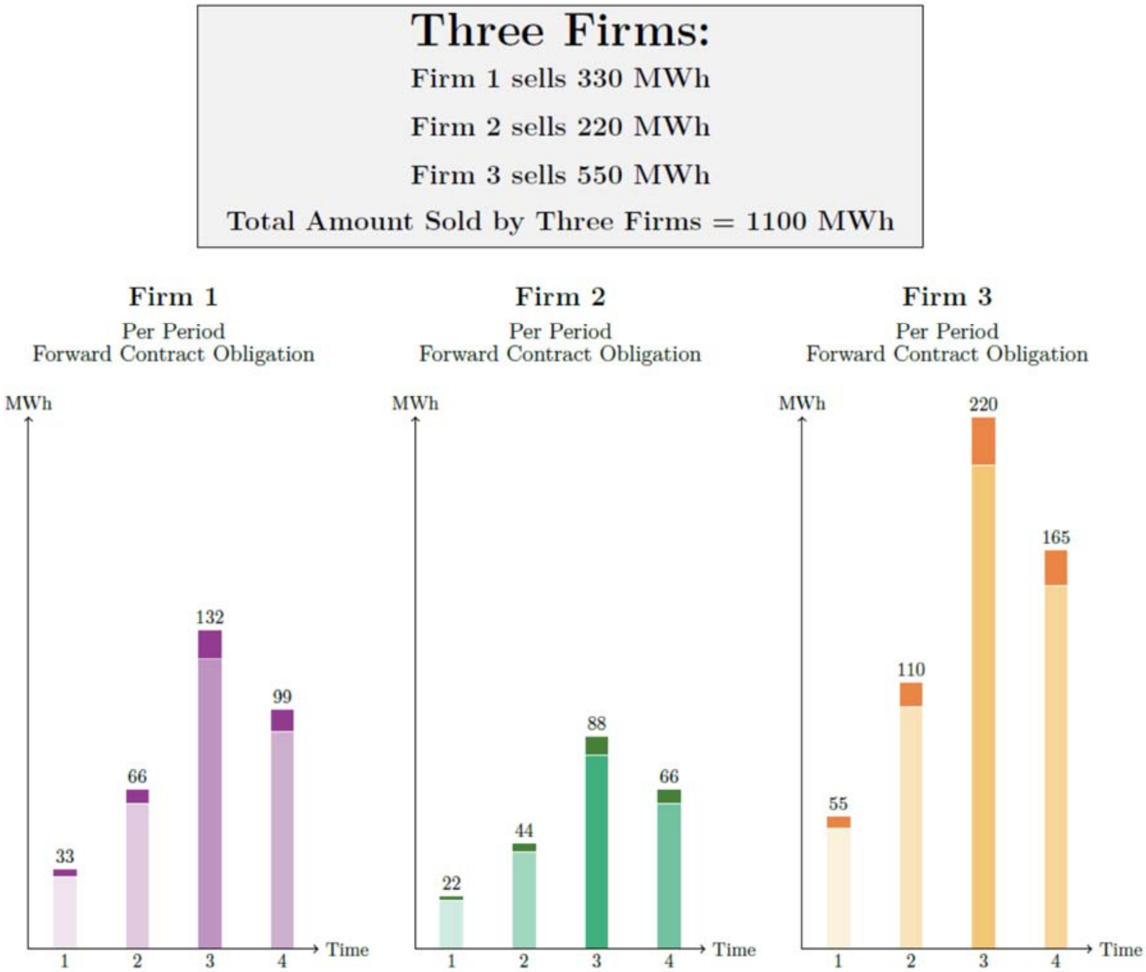

Figure 5: Hourly Forward Contract Quantities for Three Suppliers (10 Percent Higher)

Four Retailers:

Retailer 1 holds 110 MWh

Retailer 2 holds 220 MWh

Retailer 3 holds 330 MWh

Retailer 4 holds 440 MWh

Total Amount Held by Four Retailers = 1100 MWh

Figure 6: Hourly Forward Contract Quantities for Four Retailers (10 Percent Higher)

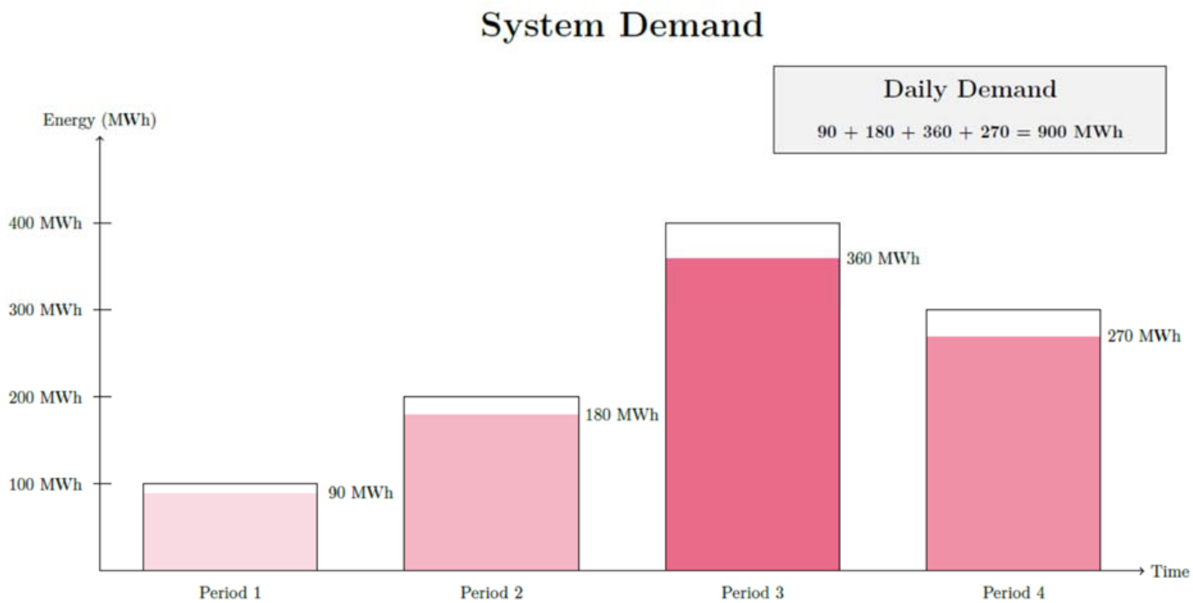

Figure 7: Hourly System Demands (10 Percent Lower)

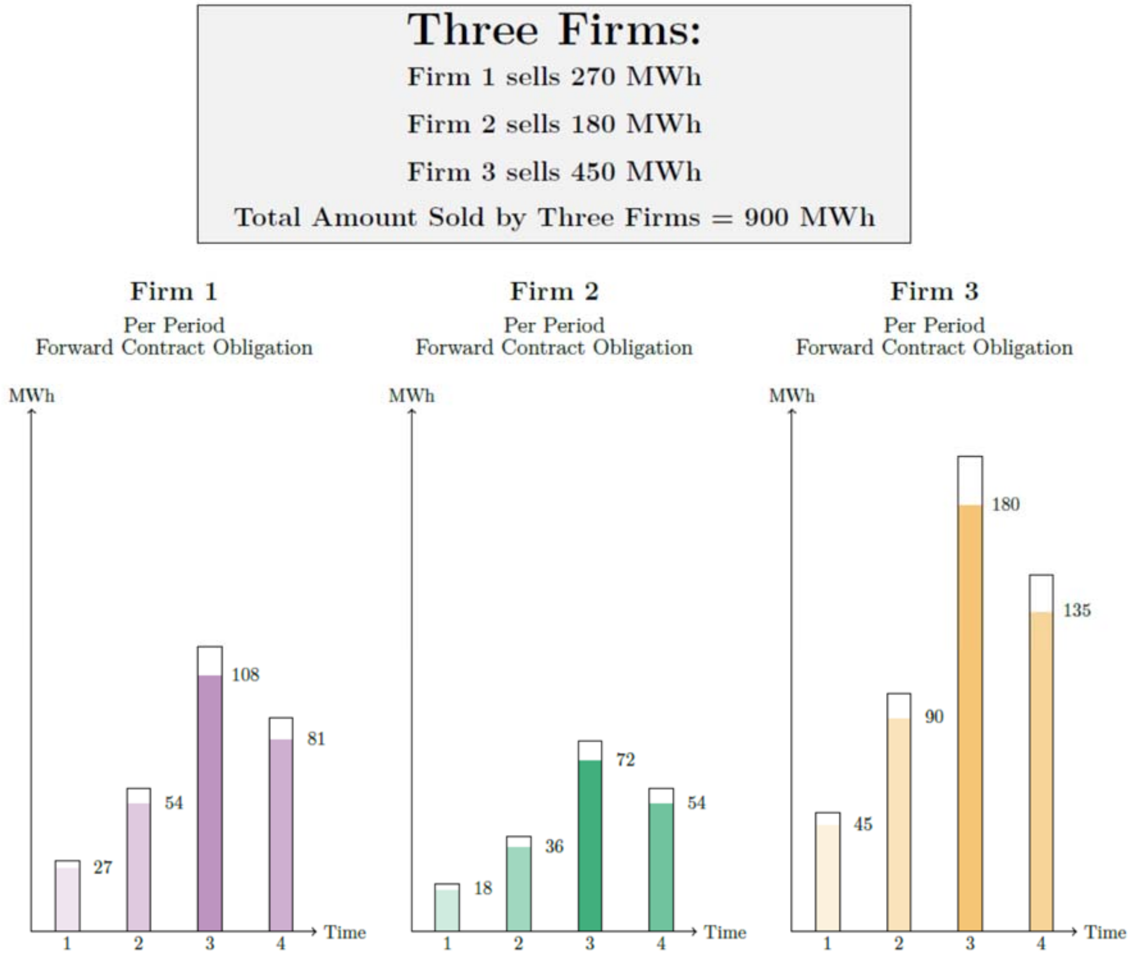

Figure 8: Hourly Forward Contract Quantities for Three Suppliers (10 Percent Lower)

Four Retailers:

Retailer 1 holds 90 MWh

Retailer 2 holds 180 MWh

Retailer 3 holds 270 MWh

Retailer 4 holds 360 MWh

Total Amount Held by Four Retailers = 900 MWh

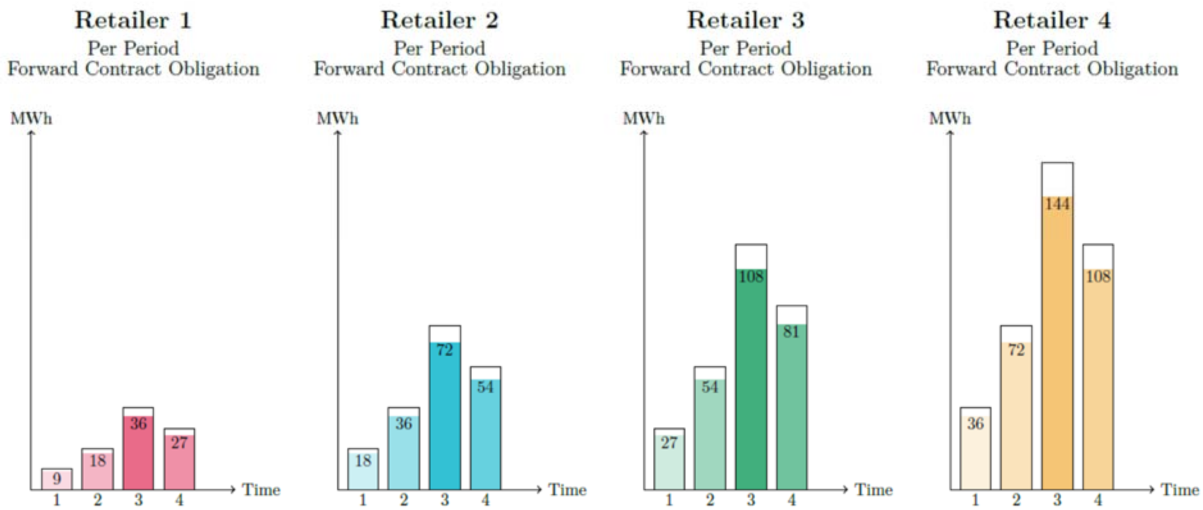

Figure 9: Hourly Forward Contract Quantities for Four Retailers (10 Percent Lower)

Energy Market Advisors LLC

Conceptual Framework for Supporting Balancing Resources in New England without the Minimum Offer Price Rules (MOPR)

Overview and Defining the Problem

According to ISO-NE, the clean energy transition in New England will depend on two types of resources - Variable Renewable Energy Resources (VRERs) and Balancing Resources (BRs).[1] VRERs will eventually become the new "baseload" resources and produce most of the electrical energy. ISO-NE notes that these resources are evolving, but still require "above market" financial support via state incentives and contracts, making them largely indifferent to wholesale market prices. BRs will be necessary to "fill in" the energy gaps, which may last from milliseconds to multiple weeks. Currently, BRs that are needed for reliability are primarily made up of Merchant Resources (non-utility owned or non-state-sponsored) and are wholly dependent on wholesale market prices. The MOPR and CASPR (Competitive Auctions with Sponsored Policy Resources) are intended to protect price formation in the capacity market, while providing a path for state sponsored resources to enter the market over time. However, if insufficient trading occurs in CASPR, the region may experience some overbuilding. ISO is concerned that if the MOPR is eliminated, price suppression could occur in the FCM and unsponsored BRs may retire prematurely, leading to uncertain reliability outcomes. In effect, removing the MOPR requires a solution to potential price suppression in the capacity market, or moving to a different resource adequacy construct. The key question ISO has posed is: "How can the market design solve for both reliability and the States' clean energy objectives?" This paper provides thoughts on this and a possible conceptual framework for addressing this question from a consumer-owned utility perspective.

Alternatives for Solving for Resource Adequacy

At the September 3, 2020 Participants Committee meeting, Rob Gramlich's presentation[2] identified six Resource Adequacy models. These are:

1. Current Capacity Construct with MOPR
2. Eliminate Broad MOPR
3. PJM Fixed Resource Requirement (FRR)
4. Voluntary-Residual Capacity Market
5. LSE Responsibility with Vertically Integrated Utility & RTO
6. LSE Responsibility with Competitive Generation and Retail Markets

Public power systems have long argued for eliminating the MOPR and/or implementing a Voluntary-Residual Capacity Market construct. As noted above, to implement either of these

[1] See Gordon Van Welie presentation to New England Council - "The Clean Energy Transition is Driving Change to New England's Wholesale Electricity Market", October 2, 2020.

[2] See Rob Gramlich presentation to NEPOOL Participants Committee - "Resource Adequacy Models and Low Carbon Markets", September 3, 2020.

approaches, the region will need to address the purported price suppression effects and the corresponding potential impact on continued operation of BRs needed for reliability. In order to achieve this outcome, we present a conceptual framework that retains much of the current New England resource adequacy construct, but replaces the MOPR and CASPR with a minimum BR constraint in the FCM.

Conceptual Framework for Replacing MOPR/CASPR with a Minimum Balancing Resource Constraint in the Forward Capacity Market (FCM)

To address the potential price suppression impacts on BRs from eliminating the MOPR, we propose consideration of a minimum BR constraint in the FCM settlement, along with selected other changes to the FCM construct. This new construct could be structured along the following lines:

1. Eliminate the MOPR for all resources.
2. Utilize Effective Load Carrying Capability (ELCC) for determining the Qualified Capacity for all resources participating in the FCM.
3. Incorporate a minimum BR requirement constraint in the primary FCA settlement.
   a) The minimum BR constraint would take the form of an MRI-type demand curve (calculated consistent with how zonal demand curves for Import and Export Zones are determined.)
   b) The rate paid to BRs that clear in the FCA should be greater than or equal to the primary FCA clearing price.
   c) A series of GE MARS (or similar software) runs starting with the Qualified Capacity of the resources that cleared in the most recent FCA could be used to calculate the change in the Expected Energy Not Served (EENS) as the relative quantity of BRs and VRERs assumed in the regional resource mix changes.
   d) The total payment to BRs (BR adder plus primary FCA system price) at the estimated total quantity of Energy Security Improvements (ESI) requirement (GCR+RER+EIR?) for the applicable FCA delivery period would be equal to Net CONE.
   e) Calculate the Scaling Factor and apply it to the BR marginal reliability impact curve to pivot the rest of the BR demand curve around this point.
4. To facilitate settlement of this construct, we would strongly suggest that the region consider changing from a “Descending Clock” auction to a “Sealed Bid” auction structure for settling the FCA.

Under this revised FCA construct, as the quantity of BRs decrease, the payments to the remaining BRs should go up. This would make up, in whole or in part, for any downward pressure on the primary FCA price associated with clearing of resources receiving support to promote State policy objectives due to elimination of the MOPR. In addition, this approach avoids challenges of integrating any Forward Clean Energy Market (FCEM) revenues into the FCM, to the extent that the region decides to pursue such mechanism. Should the region consider a Voluntary-Residual FCM construct in order to allow States to assure development of specific resources to meet State policy objectives through direct procurement of specific technologies, we believe that this approach could also facilitate this structure.

Initial Thoughts and Observations

1. Replacing the MOPR/CASPR with a minimum BR constraint provides a way of providing support to needed BRs as the share of VRERs installed on the New England system increases. To the extent elimination of the MOPR depresses the primary FCA clearing price, BRs would be somewhat insulated from any such a drop in revenues.
2. Typically, people have viewed qualifying capacity using the ELCC as a way of putting intermittent and renewable resources on a more equal footing with respect to contributions to reliability. For example, an all gas resource should have a lower ELCC than a dual fuel unit with 24 hours of firm or on site fuel. Similarly, a dual fuel resource with 10 days of firm or on site fuel should have a higher ELCC than a dual fuel unit with only 24 hours of firm or on site fuel.
3. Linking the payment to BRs to the primary FCA clearing price and a demand curve that pivots around the value of Net CONE helps preserve consistency between payments to BRs and other resources in the FCA. Explicitly calculating the reliability impacts of changes in the share of BRs on the system also helps promote linkages between the payments to BRs and their relative contributions to reliability.
4. We have tied the BR curve to the estimated ESI quantity during the FCA delivery period because it appears that ESI reflects the minimum quantity of resources with firm or stored energy supply needed to maintain reliability. ISO has previously indicated that as the quantity of VRERs installed on the system increases, the ESI quantities should also increase. This seems to be an appropriate relationship. We also believe that the ESI quantities are reasonably well understood and could be defined in a time frame to support the proposed FCA structure. With that said, we would also consider a different way of determining an "anchor" BR quantity should the ISO decide that something other than estimated ESI requirements is needed.
5. We have not considered the critical factor concerning how BRs that receive a commitment through the FCA should be settled as we approach the delivery period. Possible approaches would be to settle against the near-term ESI forward procurement mechanism under development, or absent that against the DA ESI option premium clearing price.
6. Based on what ISO has already developed, we believe that the BR demand curve structure is consistent with the principles already being applied in the FCM and should be reasonably transparent and understandable to stakeholders. Since the basic construct builds on the current capacity market model, we believe that this approach could be implemented sooner and with less difficulty than developing a totally new construct that may require developing a new set of tools from scratch.

Conclusion

The focus of this methodology has been to try and develop a framework to provide added support for BRs that are needed to maintain reliability on the New England system as it evolves over time and greater quantities of variable renewable energy resources get installed and participating in the New England markets. Clearly, these concepts will need to be better defined, tested, and refined further, but we believe that this approach holds promise for facilitating the New England grid transition in the nearer term and helping maintain resources needed to meet applicable reliability standards. We look forward to any thoughts, questions or concerns.

October 15, 2020

ISO New England:

Our companies and organizations write in support of a comprehensive exploration of future market pathways that takes into account all viable options at varying levels of development. In particular, we ask that the "Integrated Clean Capacity Market" (ICCM), first presented at the October 1, 2020 Participants Committee meeting, be given full consideration alongside other more familiar proposals on the table. We recognize that consideration of ICCM may require additional upfront development and discussion.

We view the "Future Pathways" discussions and parallel "Future Grid" study initiated by NEPOOL in response to last year's request by NESCOE as an urgent and important step to ensure that the wholesale markets can be a tool for achieving state policy goals in a competitive, reliable fashion. We appreciate ISO New England's willingness to devote resources to this effort, and the commitment to conduct additional analysis following on from the NEPOOL Participants Committee's qualitative assessment and discussion.

ISO-NE has stated that it plans to focus its quantitative analysis on carbon pricing and a Forward Clean Energy Market (FCEM), at least in part because versions of these two proposals appear to have stakeholder interest, and because they are relatively well understood, mature proposals that can be readily studied. We support ISO-NE considering these options.

Recognizing ISO-NE's stated willingness to "evaluate other pathways that may emerge in discussions with stakeholders" (Gordon van Welie presentation, Oct. 2, 2020), we want to express significant stakeholder interest in further exploring the ICCM. The ICCM merits the same level of investigation as carbon pricing and the FCEM, as the ICCM is the only option that directly addresses capacity market outcomes through an in-market solution. If wholesale markets are going to be a tool for states to achieve their clean energy objective policy requirements in a competitive fashion, capacity market reform should be under consideration. We are not pre-judging the best eventual solutions, but rather asking that the ICCM be given equal consideration.

We recognize the value in ISO-NE modeling each solution so that stakeholders have a way to compare outcomes, and after speaking with The Brattle Group, we are confident that we can collaborate with the ISO and other stakeholders and experts to provide the inputs necessary for such modeling. We are also aware that ISO-NE views an ICCM as a complex solution. However, this perceived complexity should not stop stakeholders or the ISO from considering a comprehensive response to a problem that has vexed the region for over a decade, and likely will for years to come absent a sufficiently robust solution.

We look forward to continued collaboration with ISO, NESCOE, and NEPOOL.

Sincerely,

Advanced Energy Economy;
Autumn Lane Energy Consulting[1];
Borrego Solar;
Brookfield Renewable;
Enel North America;
ENGIE North America;
Sunrun; and
Union of Concerned Scientists.

Cc: Heather Hunt, Nancy Chafetz, Sebastian Lombardi, Frank Felder, NEPOOL

[1] Autumn Lane Energy Consulting's participation in this letter does not necessarily reflect endorsement by any of its clients.