NEW ENGLAND POWER POOL

David T. Doot
Secretary

September 24, 2020

VIA ELECTRONIC MAIL

TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
RE: Supplemental Notice of October 1, 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 October meeting of the Participants Committee will be held **via teleconference on *Thursday*, October 1, 2020, at 9:00 a.m.** for the purposes set forth on the attached agenda and posted with the meeting materials at http://nepool.com/NPC_2020.php. Please note, as indicated on the Initial Agenda, that the meeting will begin in executive session, for members and alternate members or their delegates only. **The general session, which could again go late into the afternoon, will begin at the conclusion of the executive session, but in no event before 10:00 a.m**. The dial-in number for general session, to be used only by those who otherwise attend NEPOOL meetings, is **866-803-2146; Passcode: 7169224.**

For your information, except for any discussions in executive session, the October 1 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.

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

- **November 6 Sector Meetings with ISO Board Panels** – The next Sector meetings with the ISO Board are scheduled to be held virtually on Friday, November 6 (the day after the November 5 Participants Committee meeting). The ISO has requested that proposed agendas and supporting materials for those meetings be provided on or before ***Friday, October 16***. Materials can be sent directly to Maria Gulluni at mgulluni@iso-ne.com and Pat Gerity at pmgerity@dayptiney.com. We are also working to set up meetings between Sectors and state officials for those interested. We will provide further details as plans are finalized.

- **2021 NEPOOL Officers** – Each Sector needs to identify for us no later than ***Monday, October 26*** the voting member chosen by that Sector to serve as its 2021 Participants Committee officer. The Participants Committee will then select the Chair from among those Sector-selected officers, using the required voting process for that selection. We have included with this notice a memorandum that provides more information about the selection process.

We hope all of you are staying safe and healthy.

Respectfully yours,

/s/
David T. Doot, Secretary

FINAL AGENDA

Discussion on Items 1 and 2 will be held in Executive Session, during which participation will be limited exclusively to voting Members and Alternates, or their designates. A separate call-in number for this portion of the meeting will be circulated with confidential supporting materials.

1. To consider and take action, as appropriate, on an extension of the Amended and Restated Generation Information System (GIS) Administration Agreement with APX, Inc. Confidential background materials will be circulated to members and alternates under separate cover in advance of the meeting.

2. To ratify Agreements to retain a Project Administrator for the future grid study effort and a consultant to help frame discussions of future grid pathways. Background materials will be circulated to Members and Alternates under separate cover in advance of the meeting.

The remainder of the meeting will be in general session:

3. To approve the draft minutes of the September 3, 2020 Participants Committee meeting. The 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.

4. There is **NO Consent Agenda** for this meeting.

4A. To consider and take action, as appropriate, on revisions to OP-17 intended to improve tracking of load power factor and the processes for monitoring and compliance. Background materials and a draft resolution are included and posted with this supplemental notice.

4B. To consider and take action, as appropriate, on revisions to OP-21 to incorporate into the OP the annual generator winter readiness and natural gas critical infrastructure survey processes. Background materials and a draft resolution are included and posted with this supplemental notice.

5. To receive an ISO Chief Executive Officer report.

6. To receive an ISO Chief Operating Officer report.

7. To receive an ISO Draft 2021 Work Plan report. A copy of the draft Work Plan was included with the initial notice and is posted with the meeting materials.

8. To consider, and take action, as appropriate, on the following proposed budgets:

   a. 2021 ISO-NE Operating and Capital Budgets; and

   b. 2021 NESCOE Budget.

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

9. To consider and take action, as appropriate, on Installed Capacity Requirements (ICR) and Related Values for the 2024/2025 (FCA15) Capacity Commitment Period. Background materials and draft resolutions are included and posted with this supplemental notice.

[Continued on next page]

10. To consider and take action, as appropriate, on ISO-proposed Tariff revisions to exempt Energy Efficiency from FCM Pay-for-Performance Settlement, including:

    a. changes to Market Rule §§ III.13.7.2.2 through III.13.7.2.4; and

    b. changes to the Financial Assurance Policy to exclude Capacity Supply Obligations associated with Energy Efficiency measures from the calculation of FCM Delivery Financial Assurance requirements.

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

11. 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.

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

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

13. Presentation and discussion of additional potential market framework for New England in light of expected changes to the grid, and commencement of discussion on various questions and tradeoffs associated with each potential future pathway identified (i.e., the pros and cons of each pathway). A memorandum from the Chair describing the plans on this matter for the October meeting and future meetings is included and posted with this supplemental notice. Presentations to be reviewed and discussed on October 1 will be posted in advance of the meeting.

14. Administrative matters.

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

Electronic Participation Guidelines
General Session Part I - October 1, 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 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.

DURING EXECUTIVE 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 – October 1, 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 Event

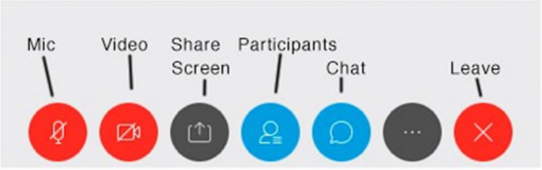
JOIN THE WEBEX EVENT
WebEx Link

- 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.

SERVICE INTERRUPTIONS

- Report issues by e-mail to the Chair or Secretary.
- If WebEx 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

v. Aug 27, 2020

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Pat Gerity, NEPOOL Counsel

DATE: September 17, 2020

RE: 2021 Participants Committee Officer Elections

In order to ensure that the selection process requirements in the Participants Committee Bylaws for 2021's Participants Committee officers can be timely completed, we need each Sector to indicate, no later than **Monday, October 26, 2020,** who the Sector has selected to serve as the Sector's Participants Committee officer. A description of the qualifications, responsibilities, and expectations of the Sector officers selected has been included with this memorandum. We urge each of you to work within your Sectors to select your Sector's 2021 Participants Committee officer.

By way of reminder, the Bylaws require that one voting member from each Sector be selected by a majority of all the voting members in its Sector (i) to serve as a nominee for Chair of the Participants Committee and (ii) if not elected Chair, to serve as a Committee Vice-Chair. A secret written balloting process will then be conducted to elect the 2021 Chair from among the Participants Committee officers selected by each of the Sectors. To allow time for that balloting process ahead of the December 3 Annual Meeting, as required by the Bylaws, we need the officers to be identified by October 26, 2020.

If any Sector needs assistance in conducting the vote for its Sector officer, please let us know (preferably no later than October 19). We would be pleased to help however we can. Also, if you have any questions, please contact me at pmgerity@daypitney.com or (860) 275-0533.

Participants Committee Sector Officer
Qualifications, Responsibilities, and Expectations

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

Responsibilities and Expectations of Participants Committee Sector Vice-Chairs:

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

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

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

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

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

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

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

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

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

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

9/17/2020

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: David Cavanaugh, Chair, GIS Agreement Working Group
Paul Belval and Lynn Fountain, NEPOOL Counsel

DATE: September 24, 2020

RE: Extension and Amendment of GIS Administration Agreement

At its October 1, 2020 meeting, the Participants Committee will be asked to approve the Extension of and First Amendment to Amended and Restated Generation Information System ("GIS") Administration Agreement between NEPOOL and APX, Inc., the GIS Administrator (the "Extension"). The Extension increases the term of the Amended and Restated GIS Administration Agreement (the "Agreement") and makes certain other changes to the Agreement. Given the commercial sensitivity of the terms of the Extension, discussion of this matter will take place in executive session. We are circulating the Extension and materials summarizing the terms of the Extension confidentially only to Participants Committee members and alternates.

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

> RESOLVED, that the Participants Committee approves the Extension of and First Amendment to 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.

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Dave Doot and Sebastian Lombardi, NEPOOL Counsel

DATE: September 24, 2020

RE: Ratification of Consulting Arrangements

You will be asked at the October 1 meeting to ratify the retention of two consultants to support the future grid meetings. The first arrangement you will be asked to ratify is for the services of Peter Flynn. He has been retained as a project administrator to assist in the ongoing joint efforts of the Reliability Committee and Markets Committee to define the future grid study or studies to be undertaken by the ISO (or a third party the ISO might designate for a study). The second arrangement to ratify is for the services of Dr. Frank Felder, who presented at the Summer Meeting and will also present at the October 1 Participants Committee meeting, as well as meetings of this Committee in November and December. His retention is to assist NEPOOL in Participants Committee discussions of the advantages and disadvantages of the various pathways that have been presented to this Committee and to report on his observations later this year.

While the identity of the retained consultants has already been made public, the details of their arrangements are competitively sensitive and any discussion about the retained individuals could also be personal. Accordingly, those details are confidential and will be shared confidentially, under separate cover, only with voting members and alternates, and discussions will only occur in executive session.

The following forms of resolution can be used for ratifying these two arrangements:

> 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.

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, September 3, 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

CONFIDENTIAL VOTE ON SLATE OF CANDIDATES FOR ISO BOARD

Ms. Chafetz reminded the Committee that the identities of the candidates on the proposed slate must remain confidential until the ISO Board reports publicly on its final vote on the slate, and indicated that discussion of this matter would proceed entirely in executive session. Ms. Chafetz then introduced Mr. Phil Shapiro, Chairman of the Joint Nominating Committee (JNC), who joined this portion of the meeting to present and answer any questions regarding the slate and the process undertaken to identify that slate. Following general comments on the process, Mr. Shapiro identified the candidates, referring to the confidential package of materials that was circulated to the members and alternates of the Committee in advance of the meeting. Ms. Chafetz then introduced Chairman Matt Nelson, Massachusetts Department of Public Utilities and Commissioner Mike Giaimo, New Hampshire Public Utility Commission, who had each participated in the JNC efforts. Chairman Nelson and Commissioner Giaimo offered their thoughts on the nomination process and the proposed slate and then left the meeting.

The slate was then discussed among members and alternates, with initial comments offered by the NEPOOL members of the JNC. A number of members suggested potential enhancements to the nominating process. Based on the discussions, the NEPOOL members of the JNC committed to explore the suggestions with the full JNC when the process for the next slate got underway in the late Fall.

Following further discussion, the following motion was duly made, seconded and approved by more than the 70% Vote required for NEPOOL endorsement, with the vote accomplished by secret written ballot per prior agreement of the Participants Committee:

> RESOLVED, that the Participants Committee endorses the slate of candidates for the ISO Board that has been recommended by the Joint Nominating Committee and presented to the Participants Committee in executive session at this meeting.

GENERAL SESSION

Following a short recess, the NEPOOL Participants Committee reconvened by WebEx Event beginning at 11:00 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.

APPROVAL OF AUGUST 6, 2020 MEETING MINUTES

Ms. Chafetz referred the Committee to the preliminary minutes of the August 6, 2020 meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of the August 6, 2020 meeting were unanimously approved as circulated, with an abstention by Mr. Michael Kuser's alternate, Mr. Rich Heidorn, noted.

ISO COO REPORT

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), reviewed highlights from the September COO report, which was circulated in advance of the meeting and posted on the NEPOOL and ISO websites. He began by providing an update on ISO operations during the continuing COVID-19 pandemic. He reported that the ISO had further pushed back the planned return of personnel to ISO facilities. As of the date of the meeting, roughly 125 employees had returned to work at ISO facilities on a voluntary basis. Given the status of the pandemic across the nation, the ISO planned to keep its facilities open for support staff on a voluntary basis through the end of 2020. The ISO planned to assess a more structured re-entry beginning in early 2021. Related to this plan, and as announced in a joint ISO and NEPOOL memo circulated to the Principal Committees the week before, NEPOOL meetings would continue to be virtual rather than in-person through the end of 2020. Monitoring of the situation with COVID-19 would continue and further updates on work and meeting plans for ISO and NEPOOL would be provided when and as appropriate.

Operations Report

Dr. Chadalavada then continued with his regular operations report. He noted that the data in the report was through August 26. He highlighted that: (i) Energy Market value for August was $273 million, down $54 million from an updated July 2020 value of $326 million and down $49 million from August 2019; (ii) August 2020 average natural gas prices were 5.8 percent lower than July average values; (iii) the average Real-Time Hub Locational Marginal Prices (LMP) for August ($25.04/MWh) were 11 percent higher than July averages; (iv) average July 2020 natural gas prices and Real-Time Hub LMPs over the period were down 24 percent and up 6.2 percent, respectively, from August 2019; (v) the average Day-Ahead cleared physical energy during peak hours as percent of forecasted load was 101.1 percent during August (up from 100.7 percent during July), with the minimum value for the month (96.6 percent) on August 22; and (vi) the Daily Net Commitment Period Compensation (NCPC) payments for July totaled $2.9 million, which was up $1.2 million from July 2020 and up $1.3 million from August 2019. August NCPC, which was 1.1 percent of total Energy Market value, was comprised of (a) $2 million in first contingency payments (up $500,000 from July); (b) $0.7 million in second contingency payments (compared to no second contingency payments in July); (c) $4,000 in voltage payments (down $18,000 from July); and (d) $195,000 in distribution payments (up $47,000 from July).

Dr. Chadalavada highlighted operational challenges in August associated with Tropical Storm Isaias in the early part of the month (with Connecticut and Western Massachusetts particularly impacted), and on August 1, 9 and 10, when loads were 1,000 to 2,000 MW over forecasted levels. During those three days, the ISO was required to dispatch fast start resources to maintain Operating Reserves, which led to the higher first contingency commitment costs for the month. He said August 9 was particularly challenging from an operational perspective because of an unplanned transmission line outage in Northeast Massachusetts/Boston (NEMA), which required out-of-market commitments in NEMA and reduced generation in SEMA. The August 9 event was relatively short duration and all reliability standards were maintained. Also in NEMA, there were planned outages in early August on two transmission lines (3163 and 3164) but those outages were cut short due to higher loads and a different merit order for dispatch than expected. The ISO also was required to make supplemental commitments for local second contingency protection in NEMA.

In response to questions, Dr. Chadalavada explained why the originally scheduled transmission outages were permitted to proceed initially even though there had been a declaration of a Pool-wide Master/Local Satellite Procedure No. 2 Abnormal Conditions Alert (M/LCC-2 Declaration). He said that an M/LCC-2 Declaration does not require all outages to be recalled. The declaration in early August was because of the impact from Isaias in Connecticut and Western Massachusetts. NEMA had not been affected by those conditions so the ISO permitted the planned outages to proceed, only to be cancelled later based on evolving circumstances. Dr. Chadalavada acknowledged that the determinations on whether to proceed with outages were inherently a balancing act, and that the ISO was studying the August events for lessons learned, and would continue to seek ways to minimize the need for out-of-market actions.

ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), referred the Committee to the summaries of the ISO Board and Board Committee meetings that had occurred since the August 6, 2020 meeting, which had been circulated and posted in advance of the meeting. He invited questions or comments on the summaries and there were none.

Mr. van Welie highlighted a virtual meeting that he and Ms. Anne George had with, and at the request of, U.S. Department of Energy (DOE) Secretary Dan Brouillette the week before the meeting. He reported that those discussions touched on all of the major issues currently under discussion in the NEPOOL processes. Mr. van Welie identified for Secretary Brouillette a number of the regional studies underway and encouraged the DOE labs to consider similar studies. He committed to keep the DOE Secretary updated on New England activities.

2021 ISO AND NESCOE BUDGETS

Mr. Robert Ludlow, ISO Vice President and Chief Financial & Compliance Officer, referred the Committee to the materials circulated and posted in advance of the meeting related to the proposed 2021 ISO Operating and Capital Budgets and the process undertaken to date. Mr. Ludlow summarized the 2021 Operating ~~budget~~Budget, which was up about two percent from the 2020 budget. He reported that key drivers of that increase included higher compensation and other inflationary costs, and planned spending on the Energy Security Improvements (ESI), renewable resources/emerging technologies impacts on market monitoring and System planning, the future grid initiative, increased software licensing and maintenance costs; and cyber security and NERC Critical Infrastructure Protection (CIP) compliance. He said headcounts and professional fees were budgeted to remain level.

Mr. Ludlow reported that the ISO's 2021 Capital Budget would remain at $28 million. As required, the ISO would review with the Budget & Finance Subcommittee and file with the FERC its quarterly filings on the Capital Budget and provide updates on specific projects as those projects move from conceptual design into chartered, active and completed projects.

Summarizing the process for budget review and approval, Mr. Ludlow said that the budgets had been reviewed with State officials and their comments on the budgets were due September 8. The ISO would respond to any comments and questions received from the States by September 23. The ISO Board would review the budgets and all feedback received at its September 16 meeting. The Participants Committee would be asked to support the final 2021 Budgets at its October 1 meeting and, with that input, the ISO Board planned to vote on the 2021 ISO Budgets thereafter. He expected that the annual Tariff filing, following Board action, would be made in mid-October, with a requested January 1, 2021 effective date.

Turning to the 2021 NESCOE Budget, Ms. Chafetz referred the Committee to the NESCOE Budget materials posted in advance of the meeting. Ms. Heather Hunt, NESCOE Executive Director, reported that the 2021 Budget conformed to the 5-year *pro forma* budget approved by the Participants Committee in June 2017 and accepted by the FERC in August 2017. She encouraged anyone with questions or comments on the NESCOE Budget to contact her.

CHANGES TO ISO-NE SELF-FUNDING TARIFF TRUE-UP MECHANISM

Ms. Michelle Gardner, Chair of the Budget and Finance Subcommittee (Subcommittee), referred the Committee to materials circulated and posted in advance of the meeting related to a change to Section IV.A of the ISO New England Transmission, Markets and Services Tariff (the

Self-Funding Tariff). Summarizing those materials, she explained that the change was to permit the ISO to carry “special purpose funds” included in one year’s budget to a subsequent year in order to complete the project for which the funds were designated. She reported that the change was considered without objection by the Subcommittee at its August 10, 2020 meeting.

The following motion was duly made and seconded:

> RESOLVED, that the Participants Committee supports revisions to the Section IV.A of the ISO New England Transmission, Markets and Services Tariff to carve special purpose funding out of the true-up mechanism, as proposed by the ISO and as circulated to this Committee with the August 27, 2020 supplemental notice, together with such non-substantive changes as may be approved by the Chair of the Budget and Finance Subcommittee.

In response to a question, Ms. Gardner confirmed that the proposed change would carve out of the Self-Funding Tariff’s true-up mechanism *any* special purpose funding that is allocated exclusively to one purpose and is maintained in a separate ledger account to be retained for use for that designated purpose in a future year. The change here would allow the ISO to apply special purpose funds established in 2020 to support Order 1000 competitive transmission solution costs in 2021. The expectation was that this sort of deferral of expense would be infrequent.

Without further discussion, the motion was then voted and approved unanimously, with an abstention on behalf of Mr. Kuser noted.

GROSS LOAD FORECAST RECONSTITUTION REVISIONS

Ms. Chafetz referred the Committee to proposed changes to Tariff Section III.12.8 (Load Forecast Reconstitution Revisions) designed to address how passive demand response (PDR) (primarily energy efficiency measures) are to be treated in the load forecast, and specifically to ensure that PDRs are not double-counted in the Forward Capacity Market (FCM).

Ms. Emily Laine, Reliability Committee (RC) Chair, summarized the RC-recommended changes and provided background for that Committee's consideration of the Load Forecast Reconstitution Revisions. She reported that, at its July 21, 2020 meeting, the RC recommended Participants Committee support for the Revisions with a vote of 60.62 percent in favor. She reported that the ISO planned to file the Revisions so that the proposed methodology could be used for the 2021 load forecast (reflected in the 2021 CELT report), and in the development of the Installed Capacity Requirement for the sixteenth Forward Capacity Auction (FCA). She also reported that market-related concerns related to the clearing of PDRs had been discussed at the August 11 Markets Committee meeting.

The following motion was duly made and seconded:

> RESOLVED, that the Participants Committee supports the Load Forecast Reconstitution Revisions, as recommended by the Reliability Committee and the ISO, and as reflected in the materials distributed to the Participants Committee for its September 3, 2020 meeting, together with such non-substantive changes as may be approved by the Chair and Vice-Chair of the Reliability Committee.

Mr. Sebastian Lombardi, NEPOOL counsel, referred the Committee to concerns with the implementation of the Load Forecast Reconstitution Revisions without a companion Market Rule change that had been raised by the New England Power Generators Association (NEPGA) at the August 11 Markets Committee meeting. He explained that NEPOOL would not raise a procedural objection at the FERC should NEPGA or any other party express those same concerns before the FERC, provided that, in raising those concerns, they do not ask the FERC to order Market Rule changes that had not otherwise been previously vetted and voted in the Participant Processes.

In discussions, a Generation Sector representative summarized concerns with the proposed methodology and the view that the changes could result in double counting of energy efficiency contributions to reliability. Others noted the reasons for their support of the proposed Revisions and expressed appreciation to the ISO for their efforts addressing the issues.

The motion was then voted and passed with a 68.22% Vote in favor (Generation Sector – 3.34%; Transmission Sector – 16.70%; Supplier Sector – 9.28%; AR Sector – 5.50%; Publicly Owned Entity Sector – 16.70%; and End User Sector – 16.70%).

LITIGATION REPORT

Mr. Doot referred the Committee to the September 1 Litigation Report that had been circulated and posted in advance of the meeting. He then highlighted the following items:

(1) ***Mystic PP-10 Complaint Denied*** – The FERC on August 17, 2020 denied a Complaint by Mystic requesting that the ISO be prohibited from implementing changes to Planning Procedure No. 10 (Planning Procedure to Support the FCM) (PP-10), starting a 30-day clock for potential requests for rehearing.

(2) ***Mystic 8/9 Cost of Service (COS) Agreement*** – Rehearings were requested of the FERC's July 17, 2020 orders in the Mystic 8/9 COS Agreement proceeding. Initial briefs in the Return on Equity (ROE) paper hearing were due September 28, 2020.

(3) ***Requests for Rehearing Denied by Operation of Law*** – Consistent with the DC Circuit's ruling in *Allegheny Defense Project v. FERC* (Allegheny), which ruled that the FERC is not allowed to delay appellate review of its substantive orders through its former practice of issuing tolling orders, the FERC issued "Notices of Denial of Rehearings by Operation of Law" of its Inventoried Energy Program (Chapter 2B) Remand Order and its order terminating the Section 206 investigation into the ISO's implementation of Order 1000 exemptions for Immediate Need Reliability Projects. That action started the clock for the filing of any appeal of those orders.

(4) ***Order 841 Compliance Filings*** - In light of the ISO's plan to submit in one filing the changes required in response to the FERC's second Order 841 compliance filing order, NEPOOL and the ISO had jointly requested a 35-day extension of time to submit the compliance filing. Expectations were that the extension would be granted, allowing for the revisions to be voted by ~~this~~the Participants Committee at its December meeting, with the compliance changes filed shortly thereafter.

COMMITTEE REPORTS

Markets Committee (MC). Ms. Chafetz reported that the MC was scheduled to meet three days, September 8-10, with discussion largely focused on FCM parameters, but would also include, among other things, consideration of proposed changes to exempt Energy Efficiency from ~~Pay for Performance~~Pay-for-Performance settlement and to sunset the Forward Reserve Market on June 1, 2025.

Budget & Finance Subcommittee~~—~~. Mr. Gerity noted that the next meeting of the Subcommittee was scheduled for October 5, at which the Subcommittee would revisit the proposed "Know Your Customer" (KYC) changes to the Financial Assurance Policy. He encouraged those interested in revisions to the KYC changes to reach out to the ISO in advance of that meeting with any questions or concerns and to plan to participate in that meeting.

Reliability Committee. Mr. Bob Stein, the RC Vice-Chair, reported that the RC was scheduled to meet on September 23 and highlighted that the Installed Capacity Requirements (ICR~~-~~) and Related Values for FCA15 would be voted at that meeting.

Generation Information System (GIS) Agreement Working Group. Mr. Dave Cavanaugh, Working Group Chair, reported that work was underway to finalize terms of an extension of NEPOOL's arrangements with APX as the GIS administrator. Plans were to vote on those arrangements at the October 1 Participants Committee meeting, and he encouraged anyone with any questions or concerns to contact him ahead of that vote.

Transmission Committee (TC). Mr. José Rotger, the TC Vice-Chair, reported that the TC was scheduled to meet September 15. He highlighted two items planned for that meeting -- a further discussion on Versant Power's proposal to waive Through ~~and~~or Out charges for transactions between the Northern Maine Independent System Administrator and ISO-NE Control Areas, and the FERC's directive in its second compliance filing order in the Order 841 (Electric Storage) proceeding that transmission charges for electric storage resources be waived under certain circumstances.

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 reminding the Committee of the process, begun in June, to explore potential alternative pathways to New England's future grid. She noted that the Committee explored two possible pathways in August -- a forward clean energy market (FCEM) and carbon pricing. She indicated that, for the remainder of the meeting, there would be presentations and discussion on two additional potential pathways – an energy-only market and alternative reliability assurance frameworks.

Energy-Only Market

Ms. Chafetz introduced Ms. Beth Garza, Senior Fellow with R Street Institute and former Director of the Electric Reliability Council of Texas (ERCOT) Independent Market Monitor, who provided an overview of ERCOT's Energy-Only Market. Ms. Garza referred the Committee to, and proceeded to review, a presentation that had been posted in advance of the meeting. After providing an overview of the ERCOT region, Ms. Garza identified that the

ERCOT organized market relies solely on Energy (no market for installed capacity, load serving entities have no requirement to own or procure installed capacity), decentralized capacity commitment (with daily and hourly reliability unit commitment filling any gaps and very low installed reserve margins), relatively large ancillary service requirements (procured only Day-Ahead, and not co-optimized in Real-Time), and its potential for very high wholesale electricity prices during times of high load (driven by natural gas prices and particularly by the availability of operating reserves with its adders and penalty mechanisms).

She described how ERCOT's decarbonization had been facilitated by the fact that Texas has areas that are especially well-suited for high performing wind and solar resources, while costs for those resources were falling. Further, as a single state, Texas was able to support financially across the state large transmission upgrades to move power from those resources to the load centers. Key issues going forward would be whether the market would continue to support the appropriate amount and cost of installed reserves. She also highlighted the potential for technology to enable decentralized reliability decisions. Importantly, ERCOT's Energy-Only market, with its hallmark periods of very high energy prices, continued to receive the support of Texas politicians and regulators.

Following her presentation, Ms. Garza responded to questions and comments. She clarified aspects of ERCOT's interconnection procedures and requirements, highlighting how those requirements, particularly those that socialized marginal transmission losses and the cost of transmission upgrades not otherwise taken on voluntarily by an interconnecting generator (generators only required to pay step-up transformer costs), had facilitated development in more remote areas of Texas. Once a generation resource was interconnected, it could participate, subject to customary communication and reliability requirements, as it wished.

Addressing the participation of demand-side resources, she explained that ERCOT's transmission cost allocation ~~likely limited~~provided end user customer incentives to engage in aggressive demand response. She observed that technology had progressed sufficiently to permit usage to be managed at a micro level, which in turn could provide opportunities for retail product development that could make demand-side actions easier and more cost-effective. She was not certain whether the price differentials over time would be sufficient to support substantial growth in those customers taking advantage of the opportunities. She explained her view that demand-side resources that depend primarily on fixed capacity payments for financial viability would not do as well in ERCOT's Energy-Only market.

On the topic of price caps and price signals, Ms. Garza summarized how price caps and the Value of Lost Load (VOLL) had evolved through the Texas regulatory process. She reported that a number of fast responding gas turbines had been added to the ERCOT system, effectively disciplining prices during times of very high load. As a result, ERCOT had a more nimble gas fleet, even as it experienced exponential growth in renewable resources. She highlighted the importance, particularly in an Energy-Only market, of incenting capacity resources to be available when and as needed, which would eventually require identifying revenue sources (e.g. ancillary services markets) to support continued capital investment. All else being equal, she favored direct assignment of costs to consumers, rather than indirectly, given higher risk premium costs associated with less direct approaches.

Ms. Garza, noting the advantages of an Energy-Only market, cautioned against relying exclusively on an Energy-Only market to decarbonize the grid. She opined that, if low carbon is the goal, then there would need to be disincentives for carbon-producing resources and that would have to be accomplished through actions other than just an Energy-Only market.

Alternative Reliability Assurance Frameworks

Ms. Chafetz then introduced Ms. Sharon Reishus, Founder of Reishus Consulting and former Chair of the Maine Public Utilities Commission, who moderated a panel discussion on alternative reliability assurance frameworks with Steve Corneli, Principal and Owner of Strategies for Clean Energy Innovation, and Rob Gramlich, Founder and President of Grid Strategies LLC. They referred to presentation materials during the meeting, which were then posted with the meeting materials following the meeting.

To provide some context, referring to the presentation materials, Ms. Reishus began by summarizing the history of New England’s resource adequacy approaches and state policies. She then turned to Mr. Corneli, who with reference to a series of slides described the basic dimensions of resource adequacy markets--what he termed “the what, the who and the how”, of resource adequacy. He compared the various resource adequacy approaches used in PJM, MISO and ERCOT. He identified as important to the development of potential future frameworks the impact of RTO tariff provisions (e.g., the Minimum Offer Price Rules) on the costs for states to achieve their clean energy goals. If the tariff provisions unreasonably increase costs, he predicted that states would increasingly look to meet reliability assurance outside of federally-regulated markets; if the tariff provisions produce reasonable and justified costs, then the states would have more flexibility in working with wholesale capacity markets. He posed questions that would need to be addressed as the future resource mix changes resource adequacy’s basic dimensions.

From there, Mr. Gramlich, also referring to his power point presentation, described key aspects of a number of reliability assurance models, including models driven by a fixed resource requirement (PJM option), a voluntary residual capacity market (early RTO capacity markets), load serving entity (LSE) responsibility working with a vertically integrated utility and RTO

(MISO, SPP model), and LSE responsibility with competitive generation and retail markets (ERCOT, California, Australian models).

In response to questions and comments, Mr. Corneli stressed the importance of understanding and working towards a regional mix that would be most efficient, reliable and operate at least cost (whether through incentives, goals, procurement plans, or a mix thereof). He suggested that potential approaches to use the markets to decarbonize could include the creation of a carbon price signal to which market participants could react or, in addition, the creation of a form of centralized or coordinated system optimization. In either case, the market pathway chosen would need to ensure that other technologies could be developed and employed. The choice of approach to integrate decarbonization would require a careful balancing of economic and power system constraints, which was not likely to occur or be successful if customers were permitted to simply choose categories of resources that they preferred. Mr. Gramlich emphasized that both the system and the portfolio of resources would be critical to the integration of decarbonization, and decarbonization goals would not be achieved through one-off purchases of low or no carbon resources.

They discussed the related challenges presented by legal, jurisdictional and governance issues. Federal legislation, they explained, made clear the limited authority of the FERC over resource adequacy issues. Pragmatic solutions could be found in regional agreement, which was not foreclosed by federal legislation, and would, as a practical matter, better support a comprehensive focus on portfolio packages and how to address times of scarcity, which increasingly were not simply peak hours.

Both Messrs. Corneli and Gramlich addressed the cost-shifting issues that could arise in multi-state regions with different state resource mixes. Mr. Corneli suggested that possible approaches could include development of ultra-refined Unforced Capacity values to recognize reliability contributions (getting to the heart of the capacity obligation) or an asset-mix approach. Mr. Gramlich suggested that there would need to be (i) someone responsible for procurement for load and (ii) financial/penalty enforcement through Real-Time, scarcity-based, VOLL-based pricing.

Addressing resource specific questions, Messrs. Corneli and Gramlich, joined by Ms. Garza, explained the favorable circumstances that had led to development of wind and solar resources, as well as the reasons why certain natural gas-fired combustion turbines were also favored. With respect to storage resources, they acknowledged the ability of those resources to fill in reliability gaps, but left unresolved questions about the feasibility of long-duration storage and whether or how discharge of storage resources should be centralized or could be decentralized. They noted the computational challenges of optimizing storage resources, and the importance and value of emerging technology to make that practicably feasible. They noted the benefits of scale in jurisdictional markets and that any reduction in scale could adversely impact outcomes and approaches, and needed to be very carefully evaluated.

Next Steps~~.~~

Ms. Chafetz stated that discussion comparing the advantages and disadvantages and trade-offs among the various pathways would begin at the October 1 Participants Committee meeting. She announced that NEPOOL had retained Dr. Frank Felder, who had presented at the Summer Meeting on the advantages and disadvantages of various markets around the globe, to help frame the upcoming discussions on tradeoffs. She encouraged anyone who wished to provide input to Mr. Felder in advance of the October 1 discussion to submit that input in writing to Mr. Lombardi, who would see that the information was sent to Mr. Felder and posted on the NEPOOL website for all to see. Any initial questions from Mr. Felder on the identified pathways would similarly be posted.

There being no further business, the meeting adjourned at 4:48 p.m.

Respectfully submitted,

David Doot, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN SEPTEMBER 3, 2020 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Acadia Center	End User	***Deborah Donovan***		
Actual Energy	Supplier		***John Driscoll***	
Advanced Energy Economy	Fuels Industry Participant	***Caitlin Marquis***		
American Petroleum Institute	Fuels Industry Participant	Zoe Cadore		
American PowerNet Management	Supplier			Mary Smith
AR Small Distributed Generation (DG) Group Member	AR-DG			Andy Karetsky
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***		
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***		
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***		
Consolidated Edison Energy, Inc.	Supplier	***Norman Mah***		
Cross-Sound Cable Company (CSC)	Supplier		***José Rotger***	
Danvers Electric Division	Publicly Owned Entity		***Dave Cavanaugh***	
DC Energy	Supplier	***Bruce Bleiweis***		
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***		
Elektrisola, Inc.	End User		Gus Fromuth	
Enel X North America, Inc.	AR-LR	Greg Geller	Herb Healy	
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***		
FirstLight Power Management, LLC	Generation	***Tom Kaslow***		
Galt Power, Inc.	Supplier	***José Rotger***		
Generation Group Member	Generation	Dennis Duffy	***Abby Krich***	***Bob Stein***
Georgetown Municipal Light Department	Publicly Owned Entity		***Dave Cavanaugh***	
Great River Hydro	AR-RG			***Dan Allegretti***
Groton Electric Light Department	Publicly Owned Entity		***Brian Thomson***	

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN SEPTEMBER 3, 2020 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
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		
High Liner Foods (USA) Incorporated	End User		***William P. Short III***	
Hingham Municipal Lighting Plant	Publicly Owned Entity		***Dave Cavanaugh***	
Holden Municipal Light Department	Publicly Owned Entity		***Brian Thomson***	
Holyoke Gas & Electric Department	Publicly Owned Entity		***Brian Thomson***	
Hull Municipal Lighting Plant	Publicly Owned Entity		***Brian Thomson***	
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***		
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***	R. Tepper
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		***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			***Dan Allegretti***
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***	***Jason Frost***
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***	
Novatus Energy	AR-RG	***Stacey Fitts***		
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	***Heather Takle***		***Jason Frost***
Princeton Municipal Light Department	Publicly Owned Entity		***Brian Thomson***	
Priogen Power LLC	Supplier	***Michel Soucy***		
PSEG Energy Resources & Trade LLC	Supplier	***Joel Gordon***		
Reading Municipal Light Department	Publicly Owned Entity		***Dave Cavanaugh***	
Rowley Municipal Lighting Plant	Publicly Owned Entity		***Dave Cavanaugh***	

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN SEPTEMBER 3, 2020 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
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***	
St. Anselm College	End User	Gus Fromuth		
Sterling Municipal Electric Light Department	Publicly Owned Entity		***Brian Thomson***	
Stowe Electric Department	Publicly Owned Entity		***Dave Cavanaugh***	
Sunrun Inc.	AR-DG	Chris Rauscher		***Pete Fuller***
Taunton Municipal Lighting Plant	Publicly Owned Entity		***Dave Cavanaugh***	
Templeton Municipal Lighting Plant	Publicly Owned Entity		***Brian Thomson***	
The Energy Consortium	End User	Roger Borghesani		
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***	***Dave Norman***	
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			Jim Ginnetti
ZTECH, LLC	End User		Gus Fromuth	

ATTACHMENT 2

VOTE TAKEN AT
SEPTEMBER 3, 2020 PARTICIPANTS COMMITTEE MEETING

TOTAL

Sector	Vote 1
GENERATION	3.34
TRANSMISSION	16.70
SUPPLIER	9.28
ALTERNATIVE RESOURCES	5.50
PUBLICLY OWNED ENTITY	16.70
END USER	16.70
% IN FAVOR	**68.22**

GENERATION SECTOR

Participant Name	Vote 1
Dominion Energy Generation Mktg.	O
FirstLight Power Resources Mgmt.	O
Generation Group Member	F
Nautilus Power, LLC	O
NRG Power Marketing, LLC	O
IN FAVOR (F)	1
OPPOSED (O)	4
TOTAL VOTES	5
ABSTENTIONS (A)	0

TRANSMISSION SECTOR

Participant Name	Vote 1
Avangrid (CMP/UI)	F
Eversource Energy	F
National Grid	F
Vermont Electric Power Co.	F
Versant Power	F
IN FAVOR (F)	5
OPPOSED	0
TOTAL VOTES	5
ABSTENTIONS (A)	0

SUPPLIER SECTOR

Participant Name	Vote 1
BP Energy Company	F
Calpine Energy Services, LP	A
Castleton Comm. Merchant Trading	O
Cross-Sound Cable Company	F
DC Energy, LLC	A
Direct Energy Business, LLC	A
DTE Energy Trading, Inc.	F
Dynegy Marketing and Trade, LLC	O
Exelon Generation Company	A
Galt Power, Inc.	F
H.Q. Energy Services (U.S.) Inc.	O
LIPA	A
Mercuria Energy America, Inc	F
Priogen Power LLC	A
PSEG Energy Resources & Trade	O
IN FAVOR (F)	5
OPPOSED	4
TOTAL VOTES	9
ABSTENTIONS (A)	6

ALTERNATIVE RESOURCES SECTOR

Participant Name	Vote 1
Renewable Generation Sub-Sector	
Central Rivers Power	O
ENGIE Energy Marketing NA	A
Great River Hydro	O
Jericho Power	O
Novatus Energy	A
Wheelabrator/Macquarie	A
Small RG Group Member	A
Distributed Gen. Sub-Sector	
Borrego Solar Systems Inc.	A
Sunrun Inc.	A
Load Response Sub-Sector	
Enel X North America, Inc.	F
Maple Energy	F
Vermont Energy Investment Corp.	F
Small LR Group Member	F
Energy Federation Inc.	
Tangent Energy Solutions, Inc.	
IN FAVOR (F)	4
OPPOSED	3
TOTAL VOTES	7
ABSTENTIONS (A)	6

ATTACHMENT 2

VOTE TAKEN AT
SEPTEMBER 3, 2020 PARTICIPANTS COMMITTEE MEETING

END USER SECTOR

Participant Name	Vote 1
Conn. Office of Consumer Counsel	F
Conservation Law Foundation	A
High Liner Foods (USA) Inc.	F
Industrial Energy Consumer Group	F
Michael Kuser	A
Maine Public Advocate Office	F
Maine Skiing, Inc.	F
Mass. Attorney General's Office	F
Natural Resources Defense Council	F
NH Office of Consumer Advocate	F
PowerOptions, Inc.	F
IN FAVOR (F)	9
OPPOSED	0
TOTAL VOTES	9
ABSTENTIONS (A)	2

PUBLICLY OWNED ENTITY SECTOR

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

PUBLICLY OWNED ENTITY SECTOR (cont.)

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

.

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Eric Runge, NEPOOL Counsel

DATE: September 24, 2020

RE: Revisions to OP-17 (including changes to Appendices B & C) and OP-21

At the October 1, 2020 Participants Committee meeting, you will be asked to support revisions to Operating Procedure ("OP") 17, including changes to Appendices B and C (collectively, "OP-17") and to OP-21, each as unanimously recommended by the Reliability Committee ("RC") at its September 23, 2020 meeting. But for the timing of the votes on these revisions, they would have been on the Consent Agenda.

Summarizing, the proposed revisions to OP-17 include monitoring-related changes (the ISO to collect and plot hourly load power factor performance data and to report load power factor performance), compliance-related changes, changes to load power factor requirements and the methodology for developing load factor limits, and clean-up changes.[1] The proposed revisions to OP-21 incorporate into OP-21 the annual generator winter readiness survey process (to enhance the ISO's situational awareness of generator pre-winter preparations) and the annual natural gas critical infrastructure survey process (to ensure critical infrastructure of the interstate natural gas system is not on electrical circuits subject to automatic or manual load shedding schemes).[2] Versions of OP-17 and OP-21 marked to show the proposed changes are included with this memorandum.

The following forms of resolutions, which can be voted together absent objection, can be used for Participants Committee consideration of these two sets of changes:

> 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 [any changes agreed to at the meeting and] 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 [any changes agreed to at the meeting and] such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee.

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[1] The materials for the RC's consideration of the OP-17 revisions are available at: https://iso-ne.com/static-assets/documents/2020/09/a10_1_op17_op17b_op17c.zip.

[2] The materials for the RC's consideration of the OP-21 revisions are available at: https://iso-ne.com/static-assets/documents/2020/09/a10_2_op21.zip.

NEPOOL PARTICIPANTS COMMITTEE
OCT 1, 2020 MEETING, AGENDA ITEM #4A

Deleted: Correction Area Definitions

Style Definition: TOC 1

Style Definition: Heading 1 Text: Centered

ISO New England Operating Procedure No. 17
Load Power Factor and System Assessment

Deleted: Correction

Effective Date: draft

Deleted: June 14, 2018

References:

ISO New England Operating Procedure No. 5 - Resource Maintenance and Outage Scheduling (OP-5)

ISO New England Operating Procedure No. 12 - Voltage and Reactive Control (OP-12)

ISO New England Operating Procedure No. 14 - Technical Requirements for Generation, Demand Response Resources, Asset Related Demands and Alternative Technology Regulation Resources Appendix B – Generator and Asset Related Demand Reactive Data (OP-14B)

ISO New England Operating Procedure No. 19 - Transmission Operations (OP-19)

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II._Load Power Factor Requirement_4¶
III._Survey Procedure and Evaluation_5¶
OP-17 Revision History_6¶

Appendices:

Appendix A - Area Definitions

Appendix B - Methodology for Developing Load Power Factor Limits

Appendix C - Instructions for the ISO New England Load Power Factor Survey

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I. INTRODUCTION

This Operating Procedure (OP) establishes the ranges of acceptable load power factor (LPF) for various area within the New England Control Area, and the responsibilities of the ISO, Transmission Owners (TOs) and Transmission Customers in New England with respect to load power factors. It also describes the analysis ISO undertakes to monitor, assess and report on load power factor compliance.

A. Overview

ISO is responsible for operating all transmission facilities rated 115 kV and above. Local Control Centers (LCCs) are responsible for operating all transmission facilities rated 69 kV and below. To maintain a reliable system, ISO and the LCCs manage the pre-contingent voltage profile of the New England Transmission System[3] and the system's reactive power resources to meet reactive power demands. Managing the reactive power output of energy resources as well any dynamic and shunt reactive power elements connected to the transmission system helps supply the system's reactive losses and the reactive demand of load served by the system.

One of the key components in maintaining system voltage is the reactive demand of system load. The reactive demand component of load is often described in terms of load power factor, or LPF. The LPF is, in simple terms, the ratio of real power demand (MW) to apparent power (MVA). LPF is a key study assumption used in long range planning of the transmission system, and it is a key factor in the operation of the power system. Significant changes in LPF from that assumed in planning studies can lead to out of merit unit commitments to prevent unacceptable high or low system voltages, and potential reliability concerns, when operating the system.

B. Responsibilities

ISO monitors the LPF throughout the New England Transmission System by surveying portions of the system defined as LPF Areas in Appendix A – Area Definitions. Those Areas where LPF is not within defined acceptable LPF ranges (which are defined by the LPF used in planning or that defined by operating analyses), and/or where an Operating Issue exists, shall implement the actions listed in Part I(C)(1-2).

For purposes of this OP, the term "Operating Issue" is defined as an actual or near voltage limit exceedance condition that can not or could not be mitigated using normal operating actions excluding:

- Deviating from economic dispatch,
- Switching out a cable,
- Purchase of available emergency capacity or energy,

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[3] The New England Transmission System is defined in the ISO New England Transmission, Markets and Services Tariff (ISO Tariff) and includes the Reliability Coordinator Area/Balancing Authority Area (RCA/BAA), Bulk Electric System (BES) and NPCC bulk power system elements found within New England on the transmission network.

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- Shedding load
- Actions that go beyond what is being established by current transmission operating guides

For example, additional commitment of generators to control a post-contingent high voltage limit exceedance due to a change in load power factor is deemed a Operating Issue due to its impact on the system's ability to accommodate the limiting system condition / topology as well as the availability of generation to mitigate the voltage limit exceedance.

C. Compliance Actions

1. Operating Issue

The ISO shall conduct the initial review of any Operating Issue and depending on the results of that technical review shall:

1. Share any correlation of new system voltage Operating Issues and LPF with the VTF;
2. Review trends with the VTF and any appropriate entities and recommend corrective actions;
3. Review trends with Master / Local Control Center and Reliability Committee when appropriate

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The timeline and actions applicable when an Operating Issue is identified are as follows:

- ISO shall send a request to the LCC to confirm the TOs and Transmission Customers as recorded in Appendix C – Instructions for the ISO New England Load Power Factor Survey (OP-17C) in a non-compliant area within seven (7) business days of the event identification
- The LCC shall confirm / correct the list of TOs/Transmission Customers in the non-compliant area within seven (7) business days of receipt of the list
- ISO shall request additional data from the TO/Transmission Customer to determine the entities involved in the actual or near miss Operating Issue within seven (7) business days of receipt of LCC confirmation
- The TO/Transmission Customer shall send requested data regarding LPF operation to ISO Operations for the identified dates and times by no later than fourteen (14) business days of the data request. If the TO/Transmission Customer believes the requested data is voluminous and requires additional time to collect, they can request such additional time from the ISO.
- ISO shall send a notification of non-complicance letter(s) to the responsible Transmission Customer(s) jurisdictional Transmission Owner(s) for the identified Operating Issue within fourteen (14) business days of data submitted to ISO Operations
- Responsible Transmission Customer(s) shall submit to the ISO an action plan within forty (40) business days of receiving a non-compliance letter. Such plan shall include an expected date of a return to compliance based upon completion of the action plan
- Responsible Transmission Customer(s) shall submit evidence of implementing the action plan to come into compliance to ISO within forty (40) Business Days of submitting action plan, as well as when the action plan is complete
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2. Non-compliance with LPF Standard

The timeline and responsibility for compliance actions due to a found non-compliance with the LPF standards is as follow:

- ISO shall send a request to the LCC to confirm the identity of the TO and/or Transmission Customer(s)as recorded in OP-17C within an area presumed to be responsible for the LPF non-compliance within seven (7) business days of the LPF assessment. The request will identify selected dates / times of the area 's worst LPF performance
- The LCC shall respond to ISO's request by providing a list of the TO and/or Transmission Customer(s) presumed to be responsible for the LPF non-

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compliance within fourteen (14) business days of ISO's request

- ISO shall notify the TO(s) and/or Transmission Customer(s) presumed to be responsible for the non-compliance within seven (7) business days of receipt of the LCC supplied list

No additional actions are required from responsible Transmission Customer(s).

The ISO, following consultation with the VTF, shall determine which entities will be contacted with regard to LPF correction, and if appropriate any revision needed in the LPF standards. For instance, a set of LPF points above the established standards would not necessarily require the standards to be revised if they are not causing any reliability concerns due to economic dispatch of generation providing compliant operation of the system in the area. Such operation, though, would still result in notification to Transmission Customer(s), and their interconnecting transmission owner, responsible for the non-compliance.

II. LOAD POWER FACTOR REQUIREMENT

The ranges of acceptable LPFs within the New England Control Area (described in Appendix A – Area Definitions) are portrayed as bandwidths of LPF expressed as a function of system load level. For a specific system load level (see Figure 1), the bandwidth between a pair of limiting curves represents the range of acceptable LPFs. These ranges are determined by ISO, in coordination with the Transmission Owners, for planning and system design studies and by ISO, in consultation with the VTF, for Real-Time operations, when load power factor curve updates are warranted based on major system changes such as installation of major transmission projects, generation additions or retirements, or installation of new significant reactive power resources. Appendix B – Methodology for Developing Load Power Factor Limits - contains the study methodology used in Operations for developing the ranges of acceptable load power factors.

If the ISO determinies that the LPF acceptable ranges require updating, loadflow analysis shall be conducted by the ISO and VTF at a maximum of three distinct load levels. These load levels may be modified as system demand dictates.

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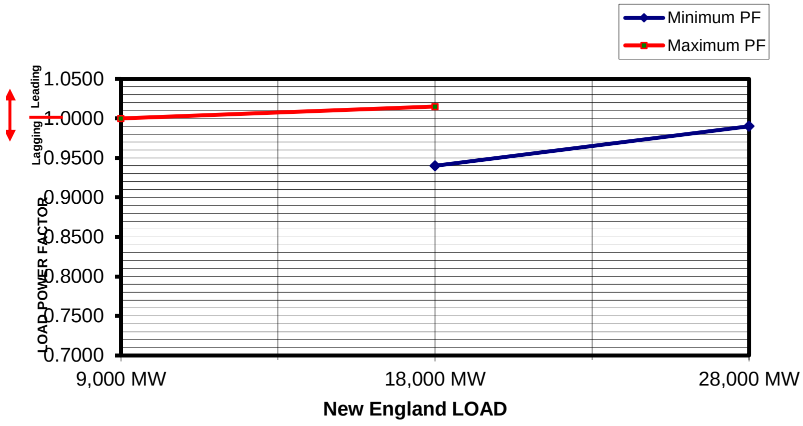

The TO and Transmission Customer have the responsibility to manage the load power factor of all connected distribution loads, and may do so by switching in or out of service transmission and distribution reactive resources to meet the LPF Area's voltage needs and, ultimately, load power factor requirements.

Generators connected to the power transmission system and sub-transmission system shall comply with the voltage schedules in OP-12B (as applicable), or as established by the local TO, and operate all units with AVRs in service, in automatic and regulating to a voltage schedule unless the units are exempted from providing voltage control under the provisions of Master/Local Control Center Procedure No.8 – Coordination of Generator Voltage Regulator and Power System Stabilizer Outages (M/LCC 8) and according to the limit of reactive capability provided under ISO New England Operating Procedure No. 14 - Technical Requirements for Generators, Demand Response Resources, Asset Related Demands and Alternative Technology Regulation Resources, Appendix B - Generator and Asset Related Demand Reactive Data Explanation of Terms and Instructions for Data Preparation for ISO Form NX-12D (OP-14B).

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The ISO, with Market Participant input through the Voltage Task Force (VTF), will conduct an annual review of the most recently developed curves to determine if they require updating. Factors to be considered are significant changes in the transmission and/or generation system, load growth, etc. If it is determined that the curves require updating, the necessary studies will be undertaken by the ISO or other members of the Voltage Task Force. ...

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III. LPF SURVEY AND ASSESSMENT PROCEDURE AND EVALUATION

A. LPF Survey

The ISO shall conduct a survey of all LPF areas annually or more frequently as circumstances may dictate. If the LPF survey shows a significant amount of LPF points ouside the established LPF curves during the surveyed period, the ISO may request additional data from TOs or Transmission Customers to determine the responsible entity or entities causing the area's non-compliance within a reasonable and agreed upon time frame. Further actions will be taken by the ISO as described in Section 1 of this OP.

The ISO is responsible for collecting the data, sharing the data with the VTF and, if necessary, requesting additional data from TOs and/or Transmission Customers to complete this analysis. The TOs and Transmission Customers are required to provided the requested data to the ISO within the time frames noted within this procedure.

The ISO shall perform the LPF survey and calculate the LPF at the transmission level, evaluate the LPF compliance, review trends and sharing the results with the VTF, M/LCC Heads and Reliability Committee. The TOs and Transmission Customers are responsible for reviewing the LPF survey results on an area basis for their load and shall provide additional data if requested by the ISO to determine the load entity or entities that were non-compliant while the Transmission Customers are responsible for developing corrective actions when required.

The information gained from performing the LPF survey, if appropriate, may then be used by the ISO to create and update system models for conducting system studies and creating new operating voltage guides, as appropriate.

B. LPF Assessment or Reliability Review

Changes in the system or perceived changes in system performance will necessitate a review and potential revision to one or more LPF's requirements for the LPF Areas. The ISO and LCC's VTF members (as needed) shall conduct studies based on the methodology described in Appendix B of this OP. Any resulting change in the LPF standards will then be used for any succeeding LPF assessments. The LPF standard is defined as a boundary, normally defined as a line or curve, where acceptable system performance occurs for LPF and load level combinations. The area on one side of the curve yields unacceptable performance while the other side yields acceptable performance. The LPF standard, or curves, shall be established using pre or post-contingent voltage limits to establish where the limiting curve point exists for defined test system load levels and sets of system conditions. For example, in Figure 1 above, the area below the red curve and above the blue curve would yield combinations of load power factor and system load where reliable operation with respect to voltage limit should be able to occur (for all lines in-service and specific facility out conditions). The area above the red curve and below the blue curve should result in either potential high or low post-contingent system operation, respectively.

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LPF assessments determine the level of shunt compensation required to return the area in question to LPF compliance. The assessment determines the change in shunt capacitance, or reactance, to return the area's LPF to within the defining curves for a low voltage, or high voltage, exceedance, respectively. These shunt compensation levels are reasonable estimates of the net relative change in area power factor that would need to occur to return the area to LPF compliance.

When an Operating Issue is identified, the ISO shall perform a reliability review. For the reliability review, if the LPF assessment shows that actual or near voltage limit exceedances from the sytem are strongly correlated with the LPF Area's performance, the results will then be compared against the area's existing LPF standards to determine the amount of LPF correction needed to improve reliability. The ISO, after consultation with the VTF, shall determine the amount of shunt capacitors or reactors improve reliability. If the ISO determines that a new LPF standard is needed for any of the LPF Areas due to an Operating Issue, the VTF shall develop the new standard and share the new requirements through the annual report on Load Power Factor.

The ISO shall annually provide a report to M/LCC Heads and Reliability Committee on LPF compliance by LPF Area, highlight future reactive targets and any Operating Issue created by the LPF performance. The report shall also include a summary of the LPF survey, assessment or reliability review and list the non-compliance notifications issued by the ISO either due to general area LPF non-compliance or for Operating Issues impacted by poor LPF as described in Part 1, above. Any new LPF standards developed for any of the LPF areas shall be updated and shared with the Transmission Customers and TOs so that they know the area's LPF requirements.

This OP is intended to complement other ISO New England Operating Procedures and help ensure reliable operation of the transmission system. It also directly supports the goals of ISO New England Operating Procedure No.19 - Transmission Operation (OP-19), which prescribes criteria for the reliable operation of the transmission system including voltage and reactive limitations and contingencies.

IV. OP-17 REVISION HISTORY

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

Rev. No.	Date	Reason
Rev 1	03/07/03	
Rev 2	02/01/05	Updated to conform to RTO terminology
Rev 3	05/06/05	Update for initiation of VELCO Local Control Center
Rev 4	10/01/06	Updated for ASM Phase 2

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Rev. No.	Date	Reason
Rev 5	12/8/06	Update for changes resulting from VTF meetings
Rev 6	12/17/14	Cover page under the “Local Control Center Instructions” section - Modified “REMVE II” to “REMVEC/NGRID” and added “NSTAR”. Section II - Added a paragraph explaining how the VTF will address instances when projects assumed in-service in the forecasted LPF study are not placed in-service in the field as planned. Section III - modified Figure 1 to only plot 6 points. Removed the additional point.
Rev 6.1	07/06/16	Periodic review performed requiring no changes; Made administrative changes required to publish a Minor Revision;
Rev 6.2	06/14/18	Periodic review performed requiring no changes; Made the administrative changes (including globally updating OP-5 and OP-14 titles and replacing “REMVEC/NGRID” with “NGRID”) required to publish a Minor Revision;
Rev 6.3	04/24/20	Periodic review performed requiring no changes; Made administrative changes required to publish a Minor Revision;
Rev 7	draft	Targeted rewrite of document to describe changes in scope and process

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APPENDIX B -
METHODOLOGY FOR DEVELOPING LOAD POWER FACTOR LIMITS

References:

ISO New England Operating Procedure No. 12 - Voltage and Reactive Control Appendix B - Voltage and Reactive Schedules (OP-12B)

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ISO New England Operating Procedure No.14 - Technical Requirements for Generators, Demand Response Resources, Asset Related Demands and Alternative Technology Regulation Resources Appendix B - Generator and Asset Related Demand Reactive Data Explanation of Terms and Instructions for Data Preparation for ISO Form NX-12D (OP-14B)

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I.OVERVIEW

The methodology set forth in this Appendix shall be used to establish minimum and maximum load power factor limits for each of the 11 study areas as defined in OP-17, Appendix A at three discrete New England net load levels identified by the Voltage Task Force (VTF) as follows : heavy (28,000 MW), intermediate (18,000 MW), and light load (9,000 MW). These load levels may be modified by the VTF from time-to-time, as system changes dictate. A curve connects the two minimum points and another curve connects the two maximum points. The two curves represent the range of load power factors that establish the standard for the area. The following figure shows an example of minimum and maximum power factors for an area, as a function of load level.

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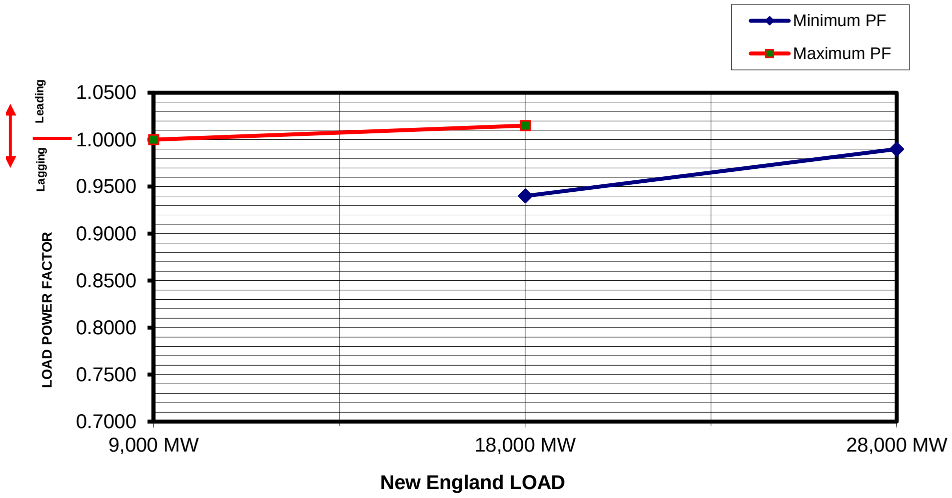
Figure 1.1: Example of Load Power Factor Curve for a Given Study Area



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II.TESTING CRITERIA

A general criterion is used to determine the minimum and maximum power factors at each load level, for all areas.

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NOTE

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1. **Minimum/Maximum Voltage** - When the study area load power factor is at its maximum, a significant number of transmission busses (69 kV and above) within the study area can’t exceed the high voltage design criteria of the Transmission Owners in the area. When the study area load power factor is at its minimum, a significant number of transmission busses (69 kV and above) within the study area can’t drop below the low voltage design criteria of the Transmission Owners in the study area. A “significant number of transmission busses” is to be determined by the VTF, on a case-by-case basis.

NOTE

Criteria described above is to be studied at each load level for all areas.

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Post-contingency analysis must be performed for the Minimum/Maximum Voltage test during all lines-in system conditions. Additionally, post-contingency analysis must be performed, typically for light and intermediate load levels (i.e., maximum load power factor standard), examining the Maximum Voltage criterion for the most limiting facility out system condition.

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For all load levels, the VTF will determine, based upon a review of results, the appropriate load power factor standard to apply.

Deleted: The load power factor standard may be chosen based upon the above described tests, whichever is more restrictive. The 0 VAr interchange criteria, even if more limiting, may **not** be appropriate to establish the load power factor requirement for all load levels (i.e., maximum and minimum load power factor standards). Consequently,

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Limiting Criterion for Minimum and Maximum Power Factor: -

To prevent load power factor over-correction in **non**-compliant Areas:

- The maximum load power factor standard must **not** fall below unity (i.e., lagging load power factor limit is **not** allowed); and
- The minimum load power factor standard must **not** fall above unity (i.e., leading load power factor limit is **not** allowed)

The minimum load power factor standard is determined by system performance at intermediate to peak load levels based upon post-contingency low voltage performance.

If the Minimum Voltage criterion indicates that a leading (above unity) minimum load power factor standard is needed, this result will be deemed unacceptable. Other transmission solutions (e.g., transmission capacitors) should be investigated.

On the other hand, the maximum load power factor standard is determined by system performance at light to intermediate load levels based upon post-contingency high voltage performance. If the Maximum Voltage criterion indicates that a lagging (below unity) maximum load power factor standard is needed, this result will be deemed unacceptable. Other transmission solutions (e.g., transmission reactors) should be investigated.

See Figures 2.1 and 2.2 below for examples of acceptable and unacceptable power factor standards. Figure 2.1 notes an example of acceptable power factor standards, in part, because neither curve crosses unity power factor. On the other hand, Figure 2.2 documents examples of unacceptable power factor curves for both the minimum and maximum power factor standard. Both curves cross the unity power factor line. These results indicate a reliance on distribution installed reactive devices to maintain acceptable transmission system voltage performance (i.e., capacitors to support low voltage concerns and reactors to support high voltage concerns).

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Figure 2.1

Example of acceptable load power factor standards

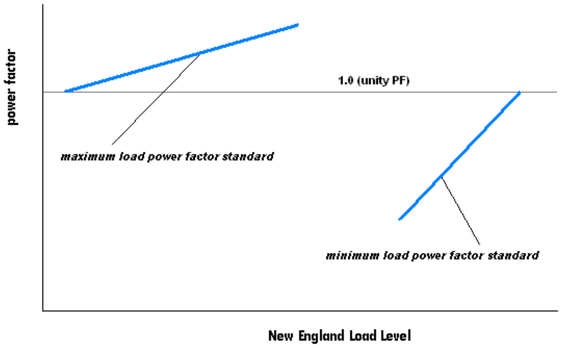
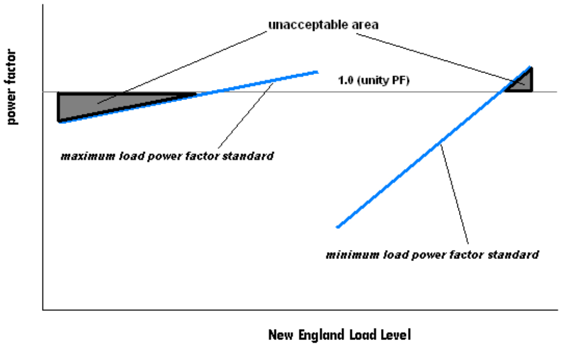


Figure 2.2

Example of unacceptable load power factor standards



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III. LOAD FLOW DEVELOPMENT

1. New England Load Levels to be Modeled

a. Heavy Net Load (28,000 MW)

b. Intermediate Net Load (18,000 MW)

c. Light Net Load (9,000 MW)

> **NOTE**
>
> New England load will be calculated as follows: Total Conforming Load + Total Non-Conforming Load + Losses.
>
> Generator Station Service loads and Pump Storage units will **not** be included in the calculation of New England load level for the purposes of these load power factor studies.

2. Load Data

a. MW loads at each bus are to be initialized using ISO projections for the appropriate net load level. MW load values contained in New England Library load flow cases are typically suitable. These will reflect appropriately applied PV and energy efficiency impacts for the studied conditions.

b. MW loads at each bus are to be scaled to the appropriate net load level (i.e. 28,000 MW, 18,000 MW or 9,000 MW).

c. Loads are independent of voltage [constant Power/Reactive (PQ) representation].

3. Generator Data and Dispatch

a. For each load level, Generators are to be dispatched economically in the base cases, assuming all New England Generators are available and respecting reserve requirements.

b. Generator voltage schedules must **not** exceed limits specified in ISO New England Operating Procedure No. 12 - Voltage and Reactive Control, Appendix B Voltage and Reactive Schedules (OP-12B).

c. Generator Reactive limits are equal to the VAr limits at Claimed Capability per ISO New England Operating Procedure No. 14 - Technical Requirements for Generators, Demand Response Resources, Asset Related Demands and Alternative Technology Regulation Resources, Appendix B – Generator and Asset Related Demand Reactive Data Explanation of Terms and Instructions for Data Preparation for ISO Form NX-12D (OP-14B), as documented on the NX-12D Forms.

d. Stations Service loads of all large Generators are to be modeled as documented on the NX-12D Forms. These loads are **not** to be tripped with the contingent Generator.

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4. Capacitors/Reactors

All sub-transmission/distribution capacitors and reactors (below 69 kV) are to be considered as part of the study area load.

NOTE

The above study requires all sub-transmission/distribution capacitors and reactors to be equivalenced with load in the load flow simulation, unless the sub-transmission is interconnected in such a way that equivalencing is **not** beneficial.

If a transmission capacitor or reactor is designated as "Local Area", the Transmission Owner **cannot** use this capacitor or reactor to determine the load power factor requirements of the study area. This avoids taking credit for the same capacitors or reactors twice, one at the study level and one at the survey level. The "Local Area" transmission capacitors or reactors listed in OP-12 Appendix B must be turned off during all testing.

5. Tie-Lines

a.

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b. Inter-Reliability Coordinator Area/Balancing Authority Area (RCA/BAA) Interface transfers tested up to transfer limits where appropriate.

c. HVDC Tie-Lines should be treated like Generators/Demand, and dispatched accordingly.

6. Solution Parameters for Contingency Testing

a. Automatic load tap changing is allowed on all tests.

b. Phase Angle Regulators (PARs) are allowed to regulate flow.

c. The system swing bus is located outside of New England with **no** regulation of RCA/BAA interchange flows.

7. Load Power Factor Measurement

The load power factor must be measured at the transmission level (i.e., at the high side of the transmission step down transformers), typically the 115 kV or 69 kV bus.

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IV.CONTINGENCIES TO BE TESTED

All normal contingencies, as defined in ISO New England Operating Procedure No. 19 - Transmission Operations (OP-19), are to be tested. These contingencies consist of individual transmission facilities (i.e., transmission lines, transformers, generators), as well as contingencies that result in the loss of multiple transmission facilities (i.e., Breaker Failure and Double Circuit Tower Contingencies) that have unacceptable inter-RCA/BAA impact.

All Special Protection Systems and Remedial Action Schemes (SPSs and RASs) are to be appropriately modeled in the load flow simulations.

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V.TESTING PROCEDURE

The testing criteria (minimum/maximum voltage) is to be applied to each study area, at each load level.

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Load flows for these tests are developed from the guidelines described in Section III of this document ("Load Flow Development"). Testing focuses on only one study area at a time. To develop a minimum load power factor limit for a given load level, the loadflow case is biased toward low voltage conditions. To develop a maximum load power factor limit for a given load level, the loadflow case is biased toward high voltage conditions.

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A. **MINIMUM LOAD POWER FACTOR -** The minimum load power factor for each load level is determined as follows.

   1. **Low Voltage Bias -** Starting from an economic dispatch, generation should be biased toward low voltage conditions:

      a. **Import Study Areas** - In study areas where less economical generation exists in comparison with the load (i.e. "Import Study Areas"), the base cases should be biased for low voltage as follows:

         1) Shut off the Generator with largest net VAr producing capability (unless such Generator is required to run for reliability reasons), within subject area.

         2) With largest Generator in study area shut off, adjust New England Transmission Interface transfers so as to depress transmission voltages within study area. Interface transfers that tend to depress study area voltages are to be dispatched up to or near existing limits, depending on the practicality of dispatch and operations at each load level. This could involve dispatching up to existing Import limits for Import Interfaces (e.g., Boston Import), and/or dispatching up to existing limits for through-flow Interfaces (e.g., North-South).

      b. **Export Study Areas** - In study areas where more economical generation exists in comparison with the load (i.e., "Export Study Areas"), the base cases should be biased for low voltage as follows:

         1) Adjust New England Transmission Interface transfers so as to depress transmission voltages within study area. This usually involves dispatching to existing export limits for the study area.

            Interface transfers that tend to depress study area voltages are to be dispatched up to or near existing limits, depending on the practicality of dispatch and operations at each load level.

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2. **Reactive Dispatch** - For each load level, VAr support from all area generation and transmission VAr sources is to be maximized:

   a. Turn on all Transmission VAr sources (e.g., Capacitor banks, STATCOMs, etc.) in the area (subject to minimum/maximum voltage schedule at all busses, as well as other constraints, e.g., Phase II filter requirements, dynamic reserve requirement for STATCOMs, etc.).

   b. Shut off all Transmission VAr absorption facilities (e.g., Reactors, etc.) in the study area (subject to minimum/maximum voltage schedule at all busses, as well as other constraints, e.g., Phase II filter requirements, dynamic reserve requirement for STATCOMs, etc.).

   c. Set voltage schedules of all study area Generators to the normal schedule.

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The general approach, when determining the minimum load power factor, is to utilize as much generation and transmission VAr support in the area as possible. Note that Distribution VAr support is to be considered part of the area load.

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<#>0 VAr Interchange Testing - For each load level, the minimum load power factor based on 0 VAr Interchange is to be determined as follows: ...

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3. **Voltage Criteria Testing** - For each load level, the minimum load power factor based on voltage criteria is to be determined as follows:

   a. Determine the contingency that results in the lowest transmission voltages in the study area

   b. Adjust the study area load power factor until a significant number of transmission busses (69 kV and above) do **not** drop below the design criteria of Transmission Owners in the study area. This power factor constitutes the minimum load power factor for the study area based on voltage criteria.

NOTE

A uniform load power factor must be applied (i.e., the same load power factor must be applied to each bus in the study area).

B. **MAXIMUM LOAD POWER FACTOR -** The maximum load power factor for each load level is determined as follows.

1. **High Voltage Bias** - Starting from an economic dispatch, generation should be biased toward high voltage conditions as follows (for either Export or Import Study Areas):

   a. Shut off the Generator with largest net VAr absorbing capability (unless such Generator is required to run for reliability reasons), within the study area.

   b. With the largest Generator in study area shut off, adjust the New England transmission interface transfers so as to inflate transmission voltages within subject area. This entails a dispatch that minimizes I^2X losses in the subject area.

2. **Reactive Dispatch** - For each load level, VAr absorption capability from all area generation and transmission VAr facilities is to be maximized:

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a. Shut off all transmission VAr sources (e.g., capacitors, etc.) in area (subject to minimum/maximum voltage schedule at all busses, as well as other constraints (e.g., Phase II filter requirements, dynamic reserve requirement for STATCOMs, etc.).

b. Turn on all transmission VAr absorption facilities (e.g., reactors, STATCOMs, etc.) in the area [subject to minimum/maximum voltage schedules at all busses, as well as other constraints (e.g., Phase II filter requirements, dynamic reserve requirements for STATCOMs, etc.)].

c. Set the voltage schedules of all study area Generators to the normal schedule.

The general approach is to utilize as much generation and transmission VAr absorption capability in the study area as possible when determining the maximum load power factor.

NOTE
Distribution reactors are to be considered part of the study area load.

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3. **Voltage Criteria Testing** - For each load level, the maximum load power factor based on voltage criteria is to be determined as follows:
   a. Determine contingency that results in the highest transmission voltages in the study area.
   b. Adjust the study area load power factor until a significant number of transmission busses (69 kV and above) do **not** exceed the design criteria of Transmission Owners in the study area. This power factor constitutes the maximum load power factor for the study area based on voltage criteria.

NOTE

A uniform load power factor must be applied (i.e., the same load power factor must be applied to each bus in the study area).

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VI.REPORT

A report shall be written for each study area, documenting all analysis conducted to determine the load power factor requirements. The report shall include the following:

- Interface Definition (i.e., list of branches that define the study area)
- Contingency List
- Base Case Summaries for all 4 load flows developed:
  1) MW and MVAr output of all major Generators in the New England RCA/BAA
  2) Dispatch of all transmission capacitors in the study area
  3) Dispatch of all transmission reactors in the study area
  4) Interface flows (MW) for all relevant transmission interfaces in the New England RCA/BAA.
  5) The New England RCA/BAA load (GW)
  6) HVDC Transfer Levels (MW)
- Study Area One-line Diagrams for all 4 load flows developed.
  An example is a PSS/E Slider diagram of the studied area showing the studied load level and type of bias, limiting contingency, and limiting criterion (Maximum/Minimum Voltage).
- Figure 6.1 is a sample of the table, which itemizes the minimum and maximum power factor case results for each load level.

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Figure 6.1: Sample Report Table

(MVAr)										*(MW)*										*(MVAr)*
Supply					*Demand*					*Supply*			*Demand*							*Reserve*
Line Charging	**Area Generators:Combined MVAr Output**	**Area Xmission Capacitors: Combined MVAr Ouput**	**Tie Lines: Combined MVAr Import**	**Total MVAr Supply**	**Line Losses (I^2X)**	**Area MVAr Load**	**Area Xmission Reactors: Combined MVAr Absorbsion**	**Station Service MVAr Load**	**Total MVAr Demand**	**Area Generators:Combined MW output**	**Tie Lines: Combined MW Import**	**Total MW Supply**	**Area MW load**	**Station Service Load**	**Area MW Losses (I^2R)**	**Total MW Demand**	**Area LPF**	**Limiting Criterion**	**Area Generators: Combined MVAr Reserve**
338	300	1465	20	2123	1758	365	0	0	2123	2494	-307	2187	2100	0	87	2187	0.985	Voltage	0
378	305	1197	5	1885	1221	659	0	0	1880	1976	-339	1637	1565	0	72	1637	0.922	VAR Interchange	0
241	-78	621	-38	746	693	-267	320	0	746	1416	165	1581	1565	0	16	1581	1.014	Voltage	0
294	-41	446	11	710	228	2	480	0	710	589	267	856	852	0	4	856	1.000	VAR Interchange	0

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OP-17, Appendix B Revision History

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

Rev. No.	Date	Reason
Rev 1	03/07/03	
Rev 2	02/01/05	Updated to conform to RTO terminology
Rev 3	06/02/05	Revised data resulting from Voltage Task Force review
Rev 4	09/07/06	Update for changes resulting from VTF meetings
Rev 5	10/01/06	Revised for ASM Phase 2
Rev 6	11/18/10	Biennial review by procedure owner; Editorial changes including font change, format changes, clarification of directed actions, added References Section, added Table of Contents, added disclaimer on page 1 and added uncontrolled to all pages, defined acronyms for applicable terms, Update for change of using 80% of ICU instead of 2/3 of ICU
Rev 7	05/08/14	Biennial review by procedure owner; Minor editorial and format and required administrative changes consistent with current practices and management expectations; Changed the number of areas to 11 in the introduction section to match OP17A; Made the following three major changes in the “Criteria Testing” section: 1) added language requiring additional facility out testing for light and shoulder load levels; 2) modified language to indicate 0 VAR criteria even if more limiting might not be the appropriate criterion to set the standard; and 3) clarifying the language in the “Limiting Criterion for Min/Max Power Factor” and added figures for illustration; Deleted references stating “the most limiting criteria will set the Area LPF standard” in the “Testing Procedure” section; Made the following two changes in the report section: 1) added a requirement to submit power flow area diagrams as a part of the Area LPF Study report; and 2) corrected the “Total MW Demand” and “Area LPF” values in the “Sample Report Table - Figure 1.2
Rev 8	10/29/14	In References Section, added OP-19 title and updated OP-14 title (same in the main body); Globally replace “VAR” with “VAr” in document content ; In Sections I & III & Figure 1.2: removed reference to percentage of CELT identified for the three discrete load levels studied and replaced with three discrete load levels identified by the Voltage Task Force. Added a NOTE to identify how New England loads are calculated in the LPF Studies. In Section V: made minor editorial change, added a period after the second sentence in the second paragraph.; Re-numbered Figure 1.2 to be Figure 6.1(to be consistent with figure numbering in other sections);
Rev 8.1	07/06/16	Periodic review performed requiring no changes; Made administrative changes required to publish a Minor Revision;
Rev 8.2	06/14/18	Periodic review performed requiring no changes; Made administrative changes (including updating OP-14 title) required to publish a Minor Revision;
Rev 8.3	04/24/20	Periodic review performed requiring no changes; Made administrative changes required to publish a Minor Revision

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Rev. No.	Date	Reason
Rev 9	draft	Global edits to coordinate with OP-17 rev.7 LPF business process changes; Globally eliminated zero VAr Interchange from testing criteria

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Appendix C -
Instructions for the ISO Power Factor Survey

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Instructions for the ISO Power Factor Survey

The purpose of this Appendix C to Operating Procedure No. 17 – Load Power Factor Correction and System Assessment (OP-17C) is to establish survey areas for which ISO New England (ISO) determines if individual Transmission Owners/Transmission Customers (TOs/TCs) have load power factors (LPFs) that are in compliance with the LPF standards.

The current LPF standards can be found in an excel document on ISO's website by searching for "op17_lpf_standards."

For the purposes of LPF analysis, the New England Reliability Coordinator Area/Balancing Authority Area (RCA/BAA) has been divided into study areas. The study areas were determined by the Voltage Task Force (VTF) based on common reactive/voltage characteristics and established interfaces within. TOs/TCs that cover a wide geographic area may be included in more than one study area. Table 1 of this OP-17C lists the study area(s) for each TO/TC and the reporting agents.

In response to requests from the ISO regarding LPF performance in these survey areas, TOs/TCs are expected to be as accurate as possible, and report the best available data/estimates.

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Integrated metered data (hourly integrated) ¶
Instantaneous metering (an average based on several nearby samples) and ¶
Estimates¶

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Line 1 Column No. - to be entered by ISO.¶
Line 2 Date - to be entered by ISO.¶
Line 3 Hour Ending - to be entered by ISO. ¶
The data entered for Line 1, Line 2, and Line 3 may be found on the ISO's website under Market and Operations > Pricing Reports > Zonal Information > 20XX SMD Hourly Data.¶
In this 20XX SMD Hourly Data spreadsheet, on the ISO NE CA tab, the System Load column contains the system load values that are used to determine the survey dates and times. Note that the System Load column values are subject to updates at any time throughout the year due to resettlements. Therefore the System Load column value may not match the survey system load values. The survey system load values represent the load values available when the survey form was created. The system load values used for evaluating LPF compliance will be recorded on the LPF Audit Report¶
Lines 4 & 5 Step-down Transformer Load at Sub transmission/ Distribution Level - Enter the aggregate of the real and reactive loads on the low voltage side of the transmission step-down transformers that feed load from the transmission system (69 kV or higher), incurred on the date and hour shown. Information is to be gathered from actual ...

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Table 1

Survey Areas and Reporting Agents		
Company	**Area**	**Reporting Agent**
Ashburnham	Central MA/Harriman	MMWEC
Boylston	Central MA/Harriman	MMWEC
Bozrah	Connecticut	CMEEC
Braintree	Southeast	Braintree
Central Maine Power	Maine	Central Maine Power
Chicopee	Western MA	MMWEC
CL&P dba Eversource	Southwest CT	Eversource
CL&P dba Eversource	Connecticut	Eversource
Concord	Boston	NSTAR dba Eversource
Danvers	Northeast MA	Danvers
Devens	Central MA/Harriman	National Grid
Fitchburg	Central MA/Harriman	Fitchburg
Georgetown	Northeast MA	National Grid
Green Mountain Power	Central MA/Harriman	National Grid
Green Mountain Power	New Hampshire	National Grid
Green Mountain Power	Vermont	National Grid
Groton	Central MA/Harriman	MMWEC
Groton Utilities	Connecticut	CMEEC
Groveland	Northeast MA	National Grid
Hingham	Southeast	NSTAR dba Eversource
Holden	Central MA/Harriman	MMWEC
Holyoke	Western MA	Holyoke
Hudson	Central MA/Harriman	Hudson
Hull	Southeast	MMWEC
Ipswich	Northeast MA	MMWEC
Island Corp	Vermont	National Grid
Jewett City Dept of Public Utilities	Connecticut	CMEEC
Liberty (Granite State Electric - GS WEST)	Vermont	National Grid
Liberty (Granite State Electric)	Northeast MA	National Grid
Littleton New Hampshire	New Hampshire	National Grid
Littleton Massachusetts	Northeast MA	Littleton
Mansfield	Southeast	MMWEC
Marblehead	Northeast MA	MMWEC
Massachusetts Electric	Northeast MA	National Grid
Massachusetts Electric (Southern Berkshires, Northampton and Granby excluded)	Central MA/Harriman	National Grid
Massachusetts Electric	Southeast	National Grid
Merrimac	Northeast MA	National Grid
Middleborough	Southeast	Middleborough

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Survey Areas and Reporting Agents		
Company	**Area**	**Reporting Agent**
Middleton	Northeast MA	Middleton
Mohegan Tribal Utilities Authority	Connecticut	CMEEC
Nantucket	Southeast	National Grid
Narragansett	Rhode Island	National Grid
New Hampshire Electric Coop	New Hampshire	New Hampshire Electric Coop
New Hampshire Electric Coop	Vermont	National Grid
North Attleborough	Southeast	North Attleborough
Norwich	Connecticut	CMEEC
Norwood	Southeast	NSTAR dba Eversource
NSTAR dba Eversource	Boston	NSTAR dba Eversource
NSTAR dba Eversource	Southeast	NSTAR dba Eversource
Pascoag	Rhode Island	National Grid
Paxton	Central MA/Harriman	MMWEC
Peabody	Northeast MA	MMWEC
Princeton	Central MA/Harriman	National Grid
PSNH dba Eversource	New Hampshire	PSNH dba Eversource
Reading	Northeast MA	Reading
Reading	Boston	Reading
Rowley	Northeast MA	Rowley
Shrewsbury	Central MA/Harriman	MMWEC
Sterling	Central MA/Harriman	MMWEC
South Hadley	Western MA	MMWEC
South Norwalk	Southwest CT	CMEEC
Taunton	Southeast	Taunton
Templeton	Central MA/Harriman	MMWEC
The United Illuminating Company	Southwest CT	The United Illuminating Company
The United Illuminating Company	Connecticut	The United Illuminating Company
Third Taxing District - Norwalk	Southwest CT	CMEEC
Great River Hydro	Central MA/Harriman	National Grid
Unitil Energy Systems	New Hampshire	Unitil Energy Systems
VELCO	Vermont	VELCO
Versant Power	Maine	Versant Power
Wakefield	Northeast MA	MMWEC
Wallingford	Connecticut	Wallingford
Wallingford	Southwest CT	Wallingford
West Boylston	Central MA/Harriman	MMWEC
Western Massachusetts Electric	Central MA/Harriman	National Grid
Westfield	Western MA	Westfield
NSTAR dba Eversource	Western MA	Eversource

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OP-17 Appendix C Revision History

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

Rev. No.	Date	Reason
- -	12/16/16	For previous revision history, refer to Rev 10 available through Ask ISO;
Rev 11	01/06/15	Added language to include non-conforming load fed directly from the transmission system in the LPF survey form and updated Figure 1 and Table 3 accordingly. Updated Table 1 as follows: Bangor Hydro - renamed as EMERA Maine (Bangor Hydro) CVPS (NH) - removed due to the merger with GMP, load rolled into GMP (NH) CVPS (Vermont) - removed due to the merger with GMP, load rolled into GMP (VT) CVPS (Vernon G-33) - removed due to the merger with GMP, load rolled into GMP(H/C); GMP (Tarif 1) - rolled into GMP (H/C); Granite State Electric (GS West) - renamed as Liberty (Granite State Electric GS West); Granite State Electric - renamed as Liberty (Granite State Electric) NH Elec Coop (NGRID) - removed due to the elimination of load as a result of the Monroe HVDC terminal retirement; NH Elec Coop (NU) - rolled into the PSNH load Town of Wallingford Electric Division (CT & SWCT)- removed CMEEC as reporting entity and replaced it with Town of Wallingford Electric Division Updated Table 2 as follows: Bangor Hydro renamed as EMERA Maine (Bangor Hydro)
Rev 11.1	02/20/15	Correct the Revision History, Rev 11, Date typo (replaced 01/16/15 with 01/06/15)
Rev 12	09/01/15	Throughout the whole document "Market Participant" is replaced by "Transmission Owners/Market Participants" Updated Table 1 as follows: Data row changes: Company NH Elec Coop data row deleted (rolled into the PSNH load); Corrected Narragansett and Pascoag companies Area assignment to Rhode Island Company Column changes: All listings of "NSTAR" replaced with "NSTAR dba Eversource"; 1st listing of "NU" replaced with "WMECO dba Eversource"; 2nd & 3rd listing of "NU" replaced with "CL&P dba Eversourc"; "PSNH" replaced with "PSNH dba Eversource"; Typo for company name corrected: "Narrangensett" changed to "Narragansett" Area Column changes: The area assignment for two companies, "Narragansett" and "Pascoag", changed from "Southeast" to "Rhode Island"; The following area names are changed to match OP17 Appendix A area definitions: • "Harriman/Central" changed to "Central MA/Harriman" • "CT" changed to "Connecticut" • "WMASS" changed to "Western MA" • "SWCT" changed to "Southwest CT" • "NH" changed to "New Hampshire" Reporting Agent Column changes: All listings of "NSTAR" replaced with "NSTAR dba Eversource"; All listings of "Northeast Utilities" replaced with "Eversource"; Only listing of "PSNH" replaced with "PSNH dba Eversource";
Rev 13	12/16/16	Biennial review by procedure owner; Added required corporate document identity to all footers; Instruction section: made editorial changes to clarify and be consistent with current practices and management expectations and added a closing paragraph before Table 1 to describe the start of the LPF survey process each year; Table 1 modified as follows: Company names are updated and changed to have consistent abbreviations;

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Figure 1¶
***<object>*ISO Power Factor Survey Illustration¶**

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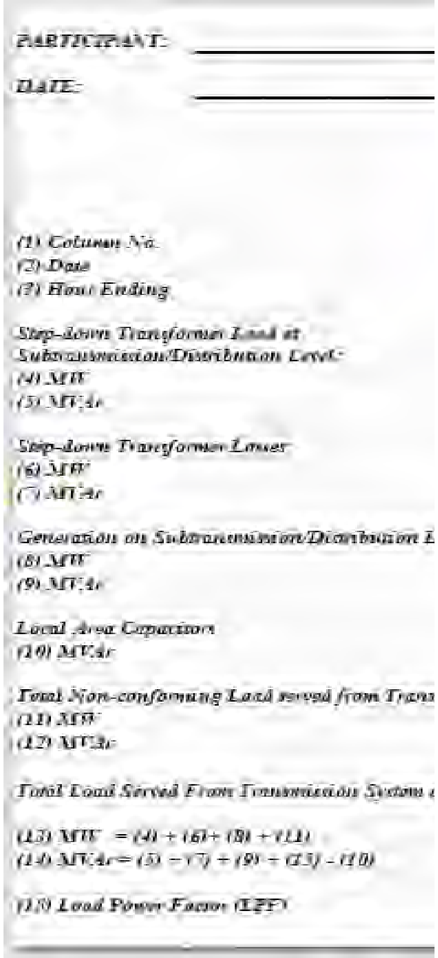
Table 3¶



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(1) Column No.
(2) Date
(3) Hour Ending

Step-down Transformer Load at Subtransmission/Distribution Level:
(4) MW
(5) MVAr

Step-down Transformer Losses
(6) MW
(7) MVAr

Generation on Subtransmission/Distribution L
(8) MW
(9) MVAr

Local Area Capacitors
(10) MVAr

Total Non-conforming Load served from Trans
(11) MW
(12) MVAr

Total Load Served From Transmission System

(13) MW = (4) + (6) + (8) + (11)
(14) MVAr = (5) + (7) + (9) + (12) - (10)

(15) Load Power Factor (LPF)

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Rev. No.	Date	Reason
		Reporting agent for Westfield is changed from MMWEC to Westfield; Sorted alphabetically after the company name updates; Truncated the Revision History per SOP-RTMKTS.0210.0010 Section 5.6;
Rev 13.1	09/26/18	Periodic review completed requiring no changes; Made administrative changes required to publish a Minor Revision;
Rev 14	05/06/19	Periodic review completed :Clarified instructions for completion of power factor survey, updated Table 1 Company names: TransCanada changed to Great River Hydro, WMECO changed to NSTAR
Rev 15	draft	Periodic review completed; modified EMERA to Versant Power; added NH Elec.Coop for NH. Major rewrite to support process changes in OP-17 r7; deleted Figure 1, Tables 2 and 3.

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ISO New England Operating Procedure No. 21 - Operational Surveys, Energy Forecasting & Reporting and Actions During An Energy Emergency

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Effective Date: draft

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References:

Federal Energy Regulatory Commission (FERC), Order No. 587 - Standards for Business Practices of Interstate Natural Gas Pipelines; Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities

FERC, Order No. 698 - Standards for Business Practices for Interstate Natural Gas Pipelines; Standards for Business Practices for Public Utilities

NAESB Standard WEQ-0011 Gas/Electric Coordination Standards

NAESB WGQ Business Practice Standards, Additional Standards; Gas/Electric Operational Communication

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

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

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

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

ISO New England Operating Procedure No. 10 - Emergency Incident and Disturbance Notifications (OP-10)

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I.INTRODUCTION

This Operating Procedure (OP) documents the processes, and establishes the associated requirements for ISO New England Inc. (ISO) to:

1. Collect fuel availability and environmental limitation information for each coal, oil, natural-gas fired, and any other Resources that ISO determines to be necessary [referred to as “applicable resource(s)” for the purposes of this OP] from each respective Lead Market Participant (Lead MP);
2. Forecast and report on expected energy availability over a 21-day look ahead period;
3. Declare Energy Alerts and Energy Emergencies based on forecasted or Real-Time system conditions;
4. Take appropriate action in anticipation of, or during, an Energy Alert or Energy Emergency;
5. Communicate with interstate natural gas pipelines, Liquefied Natural Gas (LNG) import facilities, local gas distribution companies (LDCs), Designated Entities (DEs), and Lead MPs regarding all matters related to Resource fuel availability and environmental limitations;
6. Collect information related to winter readiness preparations from each Generator Asset;
7. Collect information related to natural gas pipeline system critical infrastructure.

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This OP also documents the responsibilities of Lead MPs of applicable Resources for completion of OP-21, Appendix A - Generator Survey (OP-21A), related communications and reporting requirements, and expectations for responses related to an ISO declaration of an Energy Alert or an Energy Emergency. Nothing in this OP shall relieve Lead MPs from their obligations under the Tariff.

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Energy Emergencies (defined in Section III.C of this OP) may occur at any time as a result of sustained national or regional shortages in fuel availability or deliverability to New England’s Resources. Such shortages of fuel may occur in many forms, including, but **not** limited to: severe drought, interruption to availability or transportation of natural gas, oil, or coal.

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Any of the conditions listed below, or a combination of these conditions, may contribute to an Energy Emergency (this is not meant to be an all-inclusive list of possible initiating conditions):

- One or more pipeline operational flow orders (OFOs) have been declared
- Significant reductions of Resource capability due to natural gas-related issues
- Weather forecast for an extended period of cold or hot weather
- Fuel delivery to a significant number of fossil fuel-fired generating Resources is or may be impaired

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- Prolonged drought
- Adverse weather conditions within the Gulf of Mexico, Western Canada, or regional shale gas basins
- Abnormal conditions at regional LNG import, satellite storage, or LNG trucking facilities
- Extremely cold regional, national, or international weather conditions
- Extreme storm conditions off-shore in the Maritimes
- Any viable threat to one or more of the interstate natural gas pipelines or LDCs supplying New England
- Prolonged, significant reductions of capability to import power into the New England region
- Any other serious threat to the integrity of the Bulk Electric System (BES) for which ISO determines that the actions of this OP may mitigate the impact

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A sustained environmental limitation on some, or several, of New England’s Resources may also contribute to an Energy Emergency.

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Energy Emergencies are envisioned to last much longer than capacity deficiencies, which are managed through ISO New England Operating Procedure No. 4 - Actions During a Capacity Deficiency (OP-4) and, under extreme circumstances, through ISO New England Operating Procedure No. 7 - Actions in an Emergency (OP-7). Operable capacity deficiencies are typically experienced at seasonal peak load conditions or upon the occurrence of other emergent system conditions and tend to last for a few hours per event. Because fuel shortages and/or environmental limitations may impact New England’s ability to fully meet system load and Ten-Minute Reserve Requirement/s for days, weeks, or months at a time, ISO may need to take action in advance of a projected Energy Emergency to manage and preserve fuel supplies within the region. Unless ISO takes action to address projected Energy Emergencies, a fuel shortage and/or environmental limitations may lead to a significant loss of Resource capacity and more extreme use of OP-4 and OP-7 actions.

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The objectives of this OP are:

1. To facilitate strong lines of communication among ISO, interstate natural gas pipelines, LNG import facilities, LDCs, DEs, and Lead MPs regarding all matters relating to Resource fuel availability and environmental limitations;
2. To facilitate identification of critical infrastructure of the interstate natural gas pipeline system in order to ensure critical components are not included in automatic or manual load shed schemes
3. To alert regional stakeholders of actual or anticipated near-term energy deficiency conditions such that stakeholders with Resources in short supply of fuel, or with potential environmental limitations, can take action to replenish fuel supplies and/or take action to mitigate environmental limitations;

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4. To alert regional stakeholders of potential energy deficiencies such that they may take action to shorten or reschedule maintenance or repair to transmission facilities or Resources throughout the region;

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5. To raise the awareness of New England consumers, Lead MPs, officials of the New England states, regional and national regulators, and regional and national reliability organizations of potential energy deficiencies that may be faced by the region;
6. To allow for timely implementation of load and capacity relief available within actions of OP-4 or through implementation of load shedding through OP-7, in order to address future capacity deficiencies expected as a result of an Energy Emergency.

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II. ENERGY EMERGENCY FORECASTING AND REPORTING PROCESS OVERVIEW

A. DATA COLLECTION PROCESS DESCRIPTION

At the periodicity specified in Sections III.A, III.B, and III.C below, ISO shall distribute a blank survey form, OP-21A, to the Lead MP of each applicable Resource. The purpose of OP-21A is to collect data that allows ISO to monitor fuel inventory levels, fuel replenishment plans, and actual or anticipated environmental limitations on Resources within New England. Additionally, ISO shall utilize data submitted on OP-21A to perform periodic Energy Emergency forecasting and reporting, as described in Section II.B of this OP. ISO may report all collected data in aggregation.

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B. ENERGY EMERGENCY FORECASTING AND REPORTING PROCESS DESCRIPTION AND FORECAST ALERT THRESHOLDS

ISO shall perform Energy Emergency forecasting and reporting based on available data that includes the information received from Lead MPs through OP-21A submissions. Energy Emergency forecasting and reporting is performed at the periodicity specified in Sections III.A, III.B, and III.C. ISO performs Energy Emergency forecasting and reporting by using an hourly 21-day energy assessment, and comparing the results of that assessment with the Energy Emergency forecast alert thresholds (described below) in order to identify and communicate potential reliability issues to regional stakeholders.

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The Energy Emergency forecasts are non-binding as forecasted or expected conditions utilized in the development of the forecasts can change. It is the responsibility of the Lead MP to take all actions to ensure that Resources are able to meet applicable obligations under the Tariff.

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Energy Emergency Forecast Alert Thresholds

- Forecast MLCC-2 (FMLCC2) – indicates that available Resources during any hour of the Operating Day are forecasted to be less than 200 MW above those required to meet Operating Reserve requirements.
- Forecast Energy Emergency Alert Level 1 (FEEA1) – indicates that available Resources during any hour of the Operating Day are forecasted to be less than those required to meet Operating Reserve requirements, and that the implementation of OP-4 Actions 1 through 5 is being forecasted.
- Forecast Energy Emergency Alert Level 2 (FEEA2) – indicates that available Resources during any hour of the Operating Day are forecasted to be less than those required to meet Operating Reserve requirements and that the implementation of OP-4 Actions 6 through 11 is being forecasted.
- Forecast Energy Emergency Alert Level 3 (FEEA3) – indicates that available Resources during any hour of the Operating Day are forecasted to be insufficient to serve firm load requirements, and the implementation of firm load shedding under OP-7 is being forecasted.

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ISO shall identify and report each hour of all Operating Days within the 21-day look ahead of the Energy Emergency forecast as one of the following: normal, FMLCC2, FEEA1, FEEA2, or FEEA3.

ISO shall publish the results of each Energy Emergency forecast on the ISO website. To the extent possible, for each instance where an Energy Emergency forecast alert threshold was met, the results shall include the reason(s) why the threshold was met.

Energy Alert and Energy Emergency Declaration Criteria

ISO shall declare an **Energy Alert**, and take actions as described in Section III.B of this OP, when:

- FEEA2 or FEEA3 is forecasted to occur in at least 1 hour on 1 or more consecutive days in days 6 through 21 of the 21-day energy assessment, or
- Any other reason(s) for which the ISO Chief Operating Officer (COO), or designee, determines that the actions described in Section III.B of this OP may mitigate the impact of an actual or forecasted energy deficiency.

ISO shall declare an **Energy Emergency** and take actions as described in Section III.C of this OP, when:

- FEEA2 or FEEA3 is forecasted to occur in at least 1 hour on 1 or more consecutive days in days 1 through 5 of the 21-day energy assessment, or
- Shedding of firm load under OP-7 is occurring or is anticipated to occur due to an actual energy deficiency resulting from a sustained shortage of fuel availability or deliverability to, or sustained environmental limitations on some or several of New England Resources, or
- Any other reason(s) for which the ISO COO, or designee, determines that the actions described in Section III.C of this OP may mitigate the impact of an actual or forecasted energy deficiency.

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For the purposes of this OP, ISO shall declare Normal Conditions any time when neither an Energy Alert nor an Energy Emergency has been declared.

To the extent possible, ISO shall declare Energy Alerts and Energy Emergencies on a daily boundary.

C. COMMUNICATIONS

During Normal Conditions (as described in Section III.A of this OP), the ISO staff shall communicate with interstate natural gas pipelines/LDCs as often as necessary, dependent on existing or forecasted system conditions. More frequent communications may occur when warranted by electronic bulletin board (EBB) notices or actual pipeline conditions.

In addition to the communications that occur during Normal Conditions, during an Energy Alert or Energy Emergency (as described in Sections III.B and III.C of this

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OP, respectively) additional or enhanced electric/gas communications may be warranted. These communications serve to ascertain the status of the interstate natural gas pipelines affecting New England, and increase awareness of activities (e.g., maintenance) that may impact natural gas delivery to New England.

ISO shall communicate with interstate natural gas pipelines/LDCs in accordance with the protocols outlined in OP-21, Appendix B - Electric/Gas Operations Committee's (EGOC) Operations Communications Protocol (OP-21B).

ISO Responsibilities:

- Routine monitoring of interstate natural gas pipeline EBBs notices for indications of potential pipeline curtailments and/or restrictions. If there are indications of possible curtailments or restrictions, ISO staff is responsible for contacting the Lead MP through its DE for each applicable gas-fueled generator and seeking confirmation that each applicable gas-fueled generator has sufficient gas scheduled to its meter(s) to support its scheduled commitment for the next Operating Day.
- Contacting any interstate natural gas pipeline/LDC as necessary regarding Real-Time or forecast conditions on the regional natural gas system.
- Emailing expected electric sector gas consumption hourly load profiles to the interstate natural gas pipelines.
- Reviewing natural gas nominations, via each interstate natural gas pipeline EBB, and contacting the applicable Lead MP through its DE for its respective gas-fueled generator that may indicate a deficient natural gas supply for the current or next Operating Day.
- Contacting each dual-fuel generator after the Day-Ahead Energy Market (DAM) is complete and verifying the type of fuel it anticipates using on the next Operating Day.
- Publishing the results of the Energy Emergency Forecast on the ISO website.
- Declaring and posting Energy Alerts and Energy Emergency declarations on the ISO website.

Responsibilities of each Lead MP through its DE:

- Communicating to ISO, when such change in conditions is known, the available information regarding anticipated or actual reductions in generator availability, including but **not** limited to the ability to procure fuel and physical limitations that could reduce generator output or availability for the Operating Day.
- Communicating to ISO any knowledge of changes to Real-Time fuel deliverability, as soon as possible, to facilitate the proper commitment and dispatch of the affected generator(s).

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D. REPORTING REQUIREMENTS

- ISO shall submit all necessary reports in accordance with ISO New England Operating Procedure No. 10 - Emergency Incident and Disturbance Notifications (OP-10)**.**
- Each Lead MP shall submit all necessary reports to the extent and as required by the United States (U.S.) Department of Energy (DOE).
- Each Lead MP, through its DE, shall notify ISO when fuel supply emergencies occur that could impact BES adequacy or reliability.
- If ISO determines that Resource availability will affect the adequacy or reliability of the BES or a sub-area of the BES, ISO shall notify the U.S. DOE in accordance with Form OE-417 Electric Emergency Incident and Disturbance Report (Form OE-417) requirements.
- ISO shall report to the U.S. DOE using Form OE-417 when an Energy Emergency has been declared.
- On a case-by-case basis, ISO shall consider reporting to the U.S. DOE using Form OE-417 whenever supplies of fuel types, other than fuel oil or coal, are diminished below normal levels.

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E. DATA RETENTION REQUIREMENTS

ISO shall retain all data submitted on OP-21A for **not** less than 36 months.

ISO shall treat submitted data as Confidential Information in accordance with the ISO New England Inc. Transmission, Markets, and Services Tariff, Attachment D - ISO New England Information Policy.

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III. ACTIONS DURING NORMAL, ENERGY ALERT, AND ENERGY EMERGENCY CONDITIONS

A. NORMAL CONDITIONS

For the purpose of this OP, Normal Conditions are conditions that exist any time that neither an Energy Alert nor an Energy Emergency has been declared.

Data Collection

During Normal Conditions, on the following frequency basis, ISO shall distribute blank OP-21A forms to the Lead MPs of applicable Resources:

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- Weekly, in the months of December through March (i.e. winter months), and
- Bi-weekly, in the months of April through November (i.e., non-winter months),

ISO may increase the frequency, up to and including daily, and/or modify the data collection requirements, as necessary, if it finds emergent indications of potential energy deficiencies due to environmental limitations, fuel inventory, procurement or transportation issues, or any other condition that could limit Resource availability.

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Each Lead MP shall complete the blank OP-21A form provided by ISO for each applicable Resource and submit it to ISO as soon as possible, but **no** later than the date specified by ISO.

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- The Lead MP shall report accurate information on its completed copy of OP-21A.
- ISO may contact the Lead MP to ask clarifying questions on any submitted information.

Energy Emergency Forecasting and Reporting

During Normal Conditions, based on available data (which includes information submitted by Lead MPs on OP-21A forms), ISO shall perform Energy Emergency forecasting and reporting as follows:

- Weekly, in the months of December through March, and
- Bi-weekly, in the months of April through November

ISO shall publish results of each Energy Emergency forecast on the ISO website.

- To the extent possible, for each instance where an Energy Emergency forecast alert threshold was met, the results shall include the reason(s) why the threshold was met.

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B. ENERGY ALERT CONDITIONS

An **Energy Alert** is an alert that ISO shall declare when:

- FEEA2 or FEEA3 is forecasted to occur in at least 1 hour on 1 or more consecutive days in days 6 through 21 of the 21-day energy assessment, or
- Any other reason(s) for which the ISO COO, or designee, determines that the actions described in Section III.B of this OP may mitigate the impact of an actual or forecasted energy deficiency.

Data Collection

During Energy Alert conditions, on a daily basis, ISO shall distribute blank OP-21A forms to the Lead MPs of applicable Resources.

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ISO may increase the frequency and/or modify the data collection requirements, as necessary, if it finds emergent indications of potential energy deficiencies due to environmental limitations, fuel inventory, procurement or transportation issues, or any other condition that could limit Resource availability.

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Each Lead MP shall complete the OP-21A form provided by ISO for each applicable Resource and submit it to ISO as soon as possible, but **no** later than the date specified by ISO.

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- The Lead MP shall report accurate information on each submitted OP-21A form.
- ISO may contact the Lead MP to ask clarifying questions on any submitted information.

Energy Emergency Forecasting and Reporting

During Energy Alert Conditions, on a daily basis, ISO shall perform Energy Emergency forecasting and reporting based on available data which includes information submitted by Lead MPs on OP-21A forms.

ISO shall publish results of each daily Energy Emergency forecast on the ISO website.

- To the extent possible, for each instance where an Energy Emergency forecast alert threshold was met, the results shall include the reason(s) why the threshold was met.

Energy Alert Actions

When an Energy Alert has been declared, ISO shall:

1. Alert each LCC and surrounding Reliability Coordinator/Balancing Authority (RC/BA) of the Energy Alert.
2. Alert each Lead MP of the Energy Alert via a posting to the ISO website.

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3. Alert New England state regulators and officials of the Energy Alert.
4. Initiate daily data collection using OP-21A forms, and daily Energy Emergency forecasting and reporting.

When an Energy Alert has been declared, each Lead MP shall evaluate actual and anticipated fuel supplies and environmental limitations and should consider taking action as necessary to replenish fuel supplies and/or mitigate environmental limitations.

When an Energy Alert has been declared, each Lead MP and LCC shall evaluate scheduled maintenance or repair to transmission facilities or Resources in the region that reduces the capability of a facility or Resource to supply energy to the region and should consider taking action, if possible, to maximize availability of those facilities or Resources.

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C. ENERGY EMERGENCY CONDITIONS

An **Energy Emergency** is an emergency that ISO shall declare when:

- FEEA2 or FEEA3 is forecasted to occur in at least 1 hour on 1 or more consecutive days in days 1 through 5 of the 21-day energy assessment, or
- Shedding of firm load under OP-7 is occurring or is anticipated to occur due to an actual energy deficiency resulting from a sustained shortage of fuel availability or deliverability to, or sustained environmental limitations on, some or several of New England's Resources, or
- Any other reason(s) for which the ISO COO, or designee, determines that the actions described in Section III.C of this OP may mitigate the impact of an actual or forecasted energy deficiency.

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Data Collection

During Energy Emergency Conditions on a daily basis, ISO shall distribute a blank OP-21A form to the Lead MPs of applicable Resources.

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ISO may increase the frequency and/or modify the data collection requirements, as necessary, if it finds emergent indications of potential energy deficiencies due to environmental limitations, fuel inventory, procurement or transportation issues, or any other condition that could limit Resource availability.

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Each Lead MP shall complete the OP-21A form provided by ISO for each applicable Resource and submit it to ISO as soon as possible, but **no** later than the date specified by ISO.

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- The Lead MP shall report accurate information on the submitted OP-21A form.
- ISO may contact the Lead MP to ask clarifying questions on any submitted information.

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Energy Emergency Forecasting and Reporting

During Energy Emergency Conditions, on a daily basis, ISO shall perform Energy Emergency forecasting and reporting based on available data (which includes information submitted by the Lead MPs on OP-21A forms).

ISO shall publish results of each Energy Emergency forecast on the ISO website.

- To the extent possible, for each instance where an Energy Emergency forecast alert threshold was met, the results shall include the reason(s) why the threshold was met.

Energy Emergency Actions

When an Energy Emergency has been declared, ISO shall:

1. Alert each LCC and surrounding Reliability Coordinator/Balancing Authority (RC/BA) of the Energy Emergency.
2. Alert each Lead MP of the Energy Emergency via a posting to the ISO website.
3. Alert New England State regulators and officials of the Energy Emergency.
4. Report the Energy Emergency to the U.S. DOE, using Form OE-417.
5. Initiate daily data collection using OP-21A forms, and daily Energy Emergency forecasting and reporting.
6. Request that each dual-fuel generator scheduled to operate voluntarily switch to operation on the fuel source that is not in short supply.
7. Implement specific capacity and load relief measures available through actions of OP-4, excluding requesting New England State Governors to reinforce appeals for voluntary load curtailment.

If actions 1 - 7 above do not result in the necessary relief from the forecasted Energy Emergency, or if there is insufficient time for those measures to provide relief, the following actions may be taken:

8. Implement a New England State Governors appeal in accordance with OP-4: Request New England State Governors to reinforce appeals for voluntary load curtailment and the Power Warning Implementation.
9. Under extreme conditions, ISO shall seek reliability relief through load shedding actions available through implementation of OP-7.

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When an Energy Emergency has been declared, each Lead MP shall evaluate actual and anticipated fuel supplies and environmental limitations, and should consider taking action, as necessary, to replenish fuel supplies and/or to mitigate environmental limitations.

When an Energy Emergency has been declared, each Lead MP and LCC shall evaluate scheduled maintenance or repair to transmission facilities or Resources in

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the region that reduces the capability of a facility or Resource to supply energy to the region and should consider taking action, if possible, to maximize availability of those facilities or Resources.

D. CANCELLATION

When conditions have sufficiently improved and the criteria for declaration of an Energy Alert or an Energy Emergency are no longer being met, ISO shall cancel the Energy Alert or Energy Emergency, as applicable

To the extent possible, ISO will cancel Energy Alerts and Energy Emergencies on a daily boundary.

GENERATOR WINTER READINESS SURVEY

To facilitate ISO's situational awareness of generator readiness for operations during the winter months the ISO will annually distribute a Generator Winter Readiness Survey[1]. Survey responses are for informational purposes only.

The objectives of this survey are to facilitate ISO's understanding of the following, as it relates to the winter readiness of the region's Generator Assets:

1. Winter preparation activities;
2. Ambient temperature limitations on Real-Time capabilities or future capabilities;
3. Specific protocols followed in the event of extreme cold weather events;
4. Specific training completed prior to cold weather conditions

A. SURVEY PROCESS

Annually, prior to November 1, ISO shall distribute a survey to the Lead MPs of all Generator Assets in New England.

Each applicable Lead MP shall annually complete the survey provided by ISO and submit it to ISO as soon as possible, but **no** later than December 1, unless otherwise specified by ISO.

- The Lead MP shall report accurate information on each submitted survey.
- ISO may contact the Lead MP to ask clarifying questions on any submitted information.

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[1] The Generator Winter Readiness Survey was initially completed prior to the winter period of 2019-2020, in part, as a response to the FERC/NERC joint report, "The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018" issued on July 18, 2019.

B. SURVEY QUESTIONS

ISO shall include the following questions on the annual Generator Winter Readiness Survey. ISO may modify the survey questions, as necessary, if it determines that additional information is needed to accomplish the objectives of the Generator Winter Readiness Survey process, as described above.

1. Below what ambient temperature (°F) is it expected that this Resource would no longer be able to start?
2. Is there an identified ambient temperature (°F) at which equipment damage may occur that may potentially impact the Resource's future availability? If yes, please describe the temperature at which damage may occur and the nature of the impact(s).
3. Is the availability of this Resource's on-site primary or backup fuel supply potentially impacted by extreme cold weather? If yes, please describe the nature of this potential impact on the fuel supply and also describe what measures are in place to limit the impact of the extreme cold weather on fuel availability.
4. For natural gas-fired generators, does this Resource hold firm capacity rights on the applicable natural gas pipeline with a path from a supply source to the meter for this Resource? If yes, please provide additional clarifying information as necessary to explain the nature of those rights.
5. For natural gas-fired generators, have arrangements been made, or will they be made, to source gas for this Resource from alternate supply sources (e.g. LNG supply from Distrigas, Canaport, or Excelerate). If yes, please provide additional clarifying information as necessary to explain the nature of arrangements that have been made, or when alternate gas supply arrangements are expected to be made.
6. Are there any other specific limitations on operation and/or capability of this Resource that are anticipated due to extreme cold weather? If yes, please describe the nature of the limitation(s).
7. Did this Resource experience any equipment freeze-related or other cold weather-related issues which limited the availability of the Resource last winter? If yes, please describe the issues experienced and any remedial actions that have been taken to eliminate or minimize the potential of similar issues occurring under future similar conditions.
8. Is there a winter weather preparation procedure in place in order to prepare this Resource for winter operation?

9. By what date do you normally plan to complete the actions described in your winter weather preparation procedure?
10. Does the winter weather preparation procedure include processes, staffing plans, and timelines that direct all key activities before, during, and after severe winter weather events?
11. Does the winter weather preparation procedure include winterization of all components (e.g. freeze protection measures and technologies) that are critical for continued operation of this Resource?
12. Does the winter weather preparation procedure include performance of periodic maintenance on and inspection of freeze protection measures (e.g. inspection of heat tracing equipment and thermal insulation on critical components)?
13. Does the winter weather preparation procedure include a list of critical components

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(e.g. instruments, transmitters) that require increased surveillance during severe winter weather events?

14. Please describe any other major components of the winter weather preparation procedure for this Resource and, if necessary, providing clarifying information related to any of the responses above.
15. If the Resource does not have a specific winter weather preparation procedure in place, please describe why one may not be necessary.
16. Do staff responsible for operation of this Resource receive annual winter preparation training that highlights necessary preparations and expectations for severe winter weather events?
17. Have any improvements been made to this Resource's winter weather preparation procedure since last winter?
    a. Please describe the improvements, if any.
18. Are there any outstanding preparations or other incomplete work relating to winter readiness that would prevent this Resource from starting, or would increase the potential for this Resource to trip offline during an extreme cold weather event?

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C. DATA RETENTION REQUIREMENTS AND REPORTING

ISO shall retain all data submitted in response to Generator Winter Readiness Surveys for **not** less than 36 months.

ISO shall treat submitted data as Confidential Information in accordance with the ISO New England Inc. Transmission, Markets, and Services Tariff, Attachment D - ISO New England Information Policy.

ISO may report all collected data in aggregation.

IV. NATURAL GAS CRITICAL INFRASTRUCTURE SURVEY

To ensure that the critical infrastructure of the interstate natural gas system are not on electrical transmission or distribution circuits that may be subject to automatic or manual load shedding schemes, ISO shall annually perform a Natural Gas Critical Infrastructure Survey.

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A. SURVEY PROCESS

Annually, ISO shall distribute a survey to representatives of each interstate natural gas pipeline company operating within New England as well as the Canaport LNG facility located in Saint John, New Brunswick, CA and the Everett LNG facility in Everett, MA.

Each applicable representative should complete the survey by compiling a list of its critical facilities. Critical facilities,[2] for the purposes of this survey, include infrastructure that is critical to the reliable flow of natural gas to customers, including natural gas-fired

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[2] Examples of critical facilities, for the purposes of this survey, includes, but is not limited to; LNG liquefaction/vaporization facilities, control centers, gate stations, pipeline compressor stations, and other components/facilities deemed critical to operations by each pipeline or facility

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generating facilities and thereby requires a supply from the electrical grid to maintain operations.

ISO may modify the survey questions, as necessary, if it determines that additional information is needed to accomplish the objectives of the Natural Gas Critical Infrastructure Survey process, as described above.

ISO shall forward completed surveys to the applicable Local Control Center(s) to facilitate a review of load shedding procedures, schemes, and circuits to verify that natural gas infrastructure deemed to be critical is not connected to or located on any predefined electrical circuits.

B. SURVEY QUESTIONS

The following data points are requested for each component identified to be a critical facility:

1. Physical address of component
2. Applicable meter number
3. Feeder name/number (if known)

C. DATA RETENTION REQUIREMENTS AND REPORTING

ISO shall retain all data submitted in response to Natural Gas Critical Infrastructure Surveys for **not** less than 36 months.

ISO shall treat submitted data as Confidential Information in accordance with the ISO New England Inc. Transmission, Markets, and Services Tariff, Attachment D - ISO New England Information Policy.

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P-21 REVISION HISTORY

Rev. No.	Date	Reason
Rev 0	11/04/05	Original Version for Winter 2005/2006
Rev 1	10/13/06	Revised OP for permanent use
Rev 2	06/01/10	Updated for the changes to OP #4 actions for FCM
Rev 3	08/28/14	Biennial review by procedure owner completed; Added referenced to support new format Globally used BES in place of BPS; Added sections on actions for Energy Inventory Accounting, Normal Conditions
Rev 3.1	06/15/16	Periodic review performed requiring no changes; Made administrative changes required to publish a Minor Revision;
Rev 4	06/01/18	Biennial review by procedure owner completed; Added required corporate document identity to all page footers; Globally, minor editorial changes and updates to make content consistent with current conditions, business process practices, and management expectations; Section I Introduction 2nd paragraph, replaced "...Capacity Scarcity Condition..." with "...Capacity Shortage..." Section II.IV.B (Energy Emergency Conditions) 1st paragraph, replaced "...Capacity Scarcity Condition..." with "...Capacity Shortage...";

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Rev 5	10/19/18	Major re-write to include modified survey requirements and incorporation of Energy Emergency forecasting and reporting process.
Rev 6	draft	Biennial review by procedure owner completed; Incorporated Sections IV and V as new sections.

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Summary of ISO New England Board and Committee Meetings

October 1, 2020 Participants Committee Meeting

Since the last update, the Compensation and Human Resources Committee, the Nominating and Governance Committee, the Markets Committee, and the System Planning and Reliability Committee met by video conference on September 16. On September 17, the Audit and Finance Committee, and the Board of Directors each met by video conference.

The Compensation and Human Resources Committee reviewed details regarding the employee health benefits plan renewals for 2021. The Committee examined national compensation survey data regarding projected merit and promotional increase budgets. After reviewing information specific to the utility industry, all-industry data, and data from other system operators, the Committee approved as placeholders a 2.5% merit increase and a 0.5% promotional/equity increase for 2021, noting that the Committee would revisit and, if necessary, adjust these numbers after receiving more data in January. The Committee also discussed the work being done to attract and retain a diverse workforce and to create and maintain an inclusive work environment. The Committee reviewed proposed edits to its charter to clarify its oversight of these diversity and inclusion initiatives, and agreed to recommend a revised charter for the Board's approval. During executive session, the Committee discussed director compensation trends with the Company's compensation consultant, including how to compensate for WebEx and other meetings held virtually.

The Nominating and Governance Committee adopted resolutions recommending that the Board elect the proposed slate of directors and approve director assignments to Board committees. The Committee discussed the launch of the Joint Nominating Committee process for 2021, and also discussed potential candidate profiles and skills in connection with the Company's annual board succession process. Lastly, the Committee received an update on the political environment, including related state and federal topics.

The Markets Committee reviewed potential resource adequacy pathways for New England, and the Committee's interest in discussing the topic with states and NEPOOL sectors at upcoming meetings in November. Next, the Committee received reports on market monitoring and market performance during the spring 2020 quarter. The Committee also considered the External

Market Monitor's business continuity and succession plans, and reviewed management's responses to the recommendations included in both the Internal and External Market Monitors' Annual Reports.

The System Planning and Reliability Committee was provided with an overview of activities that were a major focus over the spring and summer of 2020, including FERC Order 1000 implementation and regional planning activities, ongoing FCM qualification process, and load forecasting enhancements. The Committee also previewed issues likely to be a focus through the end of 2020 and early 2021. The Committee then reviewed a dashboard summary of ongoing projects, feedback received on possible improvements to the Regional System Plan report, and the status of Regional System Plan projects.

The Audit and Finance Committee convened for its annual "deep dive" on cyber security issues, and reviewed progress related to the Company's cyber security work plan and operations. The full Board was invited to this meeting.

The Board of Directors held its annual meeting on September 17. Acting as the members of the Corporation, the Board elected Messrs. Colangelo, Denis and Vannoy as Directors for three-year terms. The Board also elected Ms. Abernathy as Chair and adopted the committee assignments (shown below) recommended by the Nominating and Governance Committee. Note that the significant changes include Mike Curran's succession to the chairmanship of the Audit and Finance Committee, given Chris Wilson's retirement from the Board, and the appointment of Mark Vannoy to that Committee. Mark Vannoy will also fill Chris Wilson's seat on the Markets Committee.

- Messrs. Curran, Rush and Vannoy shall serve on the **Audit and Finance Committee**, with Mr. Curran to serve as Chair;

- Mses. Abernathy and VanZandt and Messrs. Colangelo and Denis shall serve on the **Compensation and Human Resources Committee**, with Mr. Denis to serve as Chair;

- Ms. LaFleur and Messrs. Curran, Rush and Vannoy shall serve on the **Markets Committee**, with Mr. Rush to serve as Chair;

- Mses. Abernathy and LaFleur and Mr. Shapiro shall serve on the **Nominating and Governance Committee**, with Mr. Shapiro to serve as Chair;

- Ms. VanZandt and Messrs. Colangelo, Denis and Shapiro shall serve on the **System Planning and Reliability Committee**, with Ms. VanZandt to serve as Chair; and
- Ms. VanZandt and Messrs. Colangelo, Curran and Rush shall serve on the temporary **Special Committee on Information Technology and Cyber Security**, with Mr. Colangelo to serve as Chair.

The Board also elected the Company's officers for the upcoming year and agreed to consider assignments to the Joint Nominating Committee at its meeting in November.

The Board discussed management's analysis of potential resource adequacy pathways for New England and, upon the recommendation of the Markets Committee, provided direction to management to prioritize the evaluation of net carbon pricing and a forward clean energy market. Furthermore, when the Board meets with NEPOOL and NECPUC/NESCOE in early November, it would appreciate hearing stakeholder views on the various pathways being discussed in the NEPOOL "Pathways to Future Grid" initiative.

Next, the Board discussed the 2021 budgets and reviewed the states' comments on the budgets. The Board also discussed the remaining stakeholder process on the budgets, noting that the Board's vote on the budgets takes place after the Board is notified of feedback from and the vote of the NEPOOL Participants Committee.

The Board also received reports from the standing committees and Gordon's CEO report, including a quarterly update on corporate goal achievement. The Board then met in executive session to receive the report of the Compensation and Human Resources Committee regarding updates on director compensation trends and agreed to clarify its compensation policy regarding virtual meetings.

NEPOOL Participants Committee Report

October 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: August 2020 Energy Market value totaled $305M
  - September Energy market value over the period was $158M, down $148M from August 2020 and down $53M from September 2019
    - September natural gas prices over the period were 1.3% lower than August average values
    - Average RT Hub Locational Marginal Prices ($20.47/MWh) over the period were 14% lower than August averages
      - DA Hub: $20.41/MWh
    - Average September 2020 natural gas prices and RT Hub LMPs over the period were down 25% and up 0.1%, respectively, from September 2019 average
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 99.3% during September, down from 101.4% during August*
    - The minimum value for the month was 93.6% on Wednesday, September 16th

Data through September 23rd, except where otherwise noted.

Underlying natural gas data furnished by:

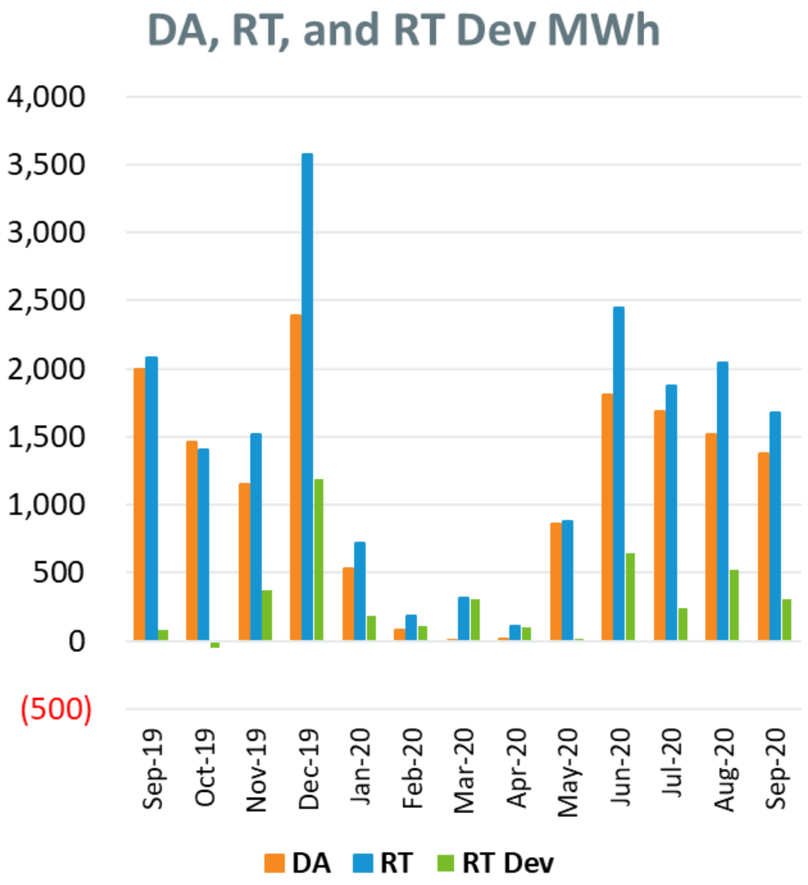
***DA Cleared Physical Energy is the sum of Generation and Net Imports cleared in the DA Energy Market**

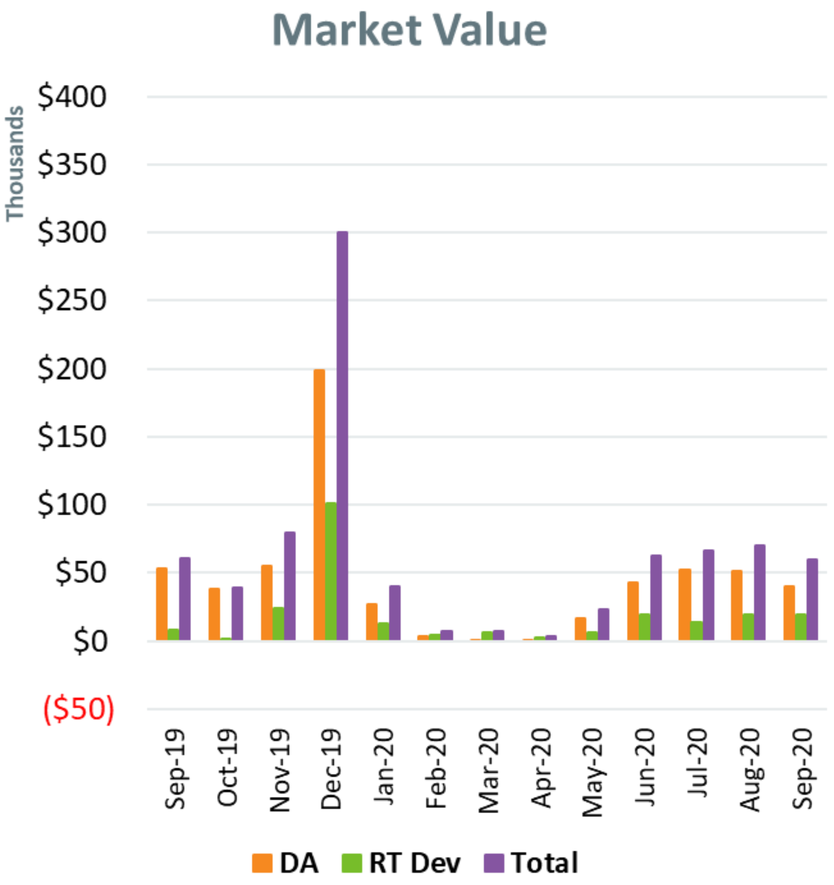
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - September NCPC payments totaled $1.9M over the period, down $1.5M from August 2020 and down $0.4M from September 2019
    - First Contingency payments totaled $1.4M, down $0.9M from August
      - $1.4M paid to internal resources, down $0.8M from August
        - » $306K charged to DALO, $582K to RT Deviations, $467K to RTLO*
      - $60K paid to resources at external locations, down $132K from August
        - » Charged to RT Deviations
    - Second Contingency payments totaled $237K, down $601K from August
    - Voltage payments totaled $262K, up $258K from August
    - Distribution payments totaled $6K, down $199K from August
  - NCPC payments over the period as percent of Energy Market value were 1.2%

* NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $99K; Rapid Response Pricing (RRP) Opportunity Cost - $188K; Posturing - $142K; Generator Performance Auditing (GPA) - $37K

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 10 (2019-2020)
  - Late, new resources (regardless of size) are being monitored closely
- 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 development for ARA3 continue at the PSPC
    - RC vote anticipated October 20, PC vote expected November 6, and FERC filing to be made by December 1

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 development for ARA2 continue at the PSPC
    - RC vote anticipated October 20, PC vote expected November 6, and FERC filing to be made by December 1
- 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 development for ARA1 continue at the PSPC
    - RC vote anticipated October 20, PC vote expected November 6, and FERC filing to be made by December 1

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 are on schedule to be released by October 2
  - ICR and related values to be filed with FERC no later than November 10

FCA – Forward Capacity Auction

Highlights

- On September 24, Transmission Planning initiated discussions with the Planning Advisory Committee regarding appropriate study assumptions to accommodate the changing landscape of the power system
- Qualification Determination Notifications are on schedule to be released by October 2
- RSP21 development will commence in Q1 2021
  - Improvements to streamline the RSP have already begun and include the addition of a new web page for Economic Studies and enhanced Environmental/Emissions information
- ICR and Related Values Development Continues
  - FCA 15 values to be filed with FERC no later than November 10
  - 2021 ARA values to be filed with FERC by December 1
- EE Reconstitution Project
  - Reconstitution methodology changes to MR1, Section 12.8(d) were filed with FERC on September 11 and will impact the 2021 load forecast used for FCA 16 ICR and Related Values development

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

FERC Order 1000

- Qualified Transmission Project Sponsor (QTPS)
  - 25 companies have achieved QTPS status
- The Boston 2028 RFP process has been completed and the ISO has started the Solutions Study process
  - The Preliminary Preferred Solution was discussed at the 8/27/20 PAC meeting
  - The draft Solutions Study was issued on 9/8/20 and stakeholder comments were due on 9/23/20
    - No stakeholder comments were received
    - The final Solutions Study was issued on 9/24/20

Highlights

- The lowest 50/50 and 90/10 Fall Operable Capacity Margins are projected for week beginning October 17, 2020.

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

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Below Normal (-0.4°F) Max: 85°F, Min: 44°F Precipitation: 0.46” – Below Normal Normal: 3.06”	Hartford	Temperature: Below Normal (-0.1°F) Max: 86°F, Min: 33°F Precipitation: 0.97” - Below Normal Normal: 3.42”

Peak Load:	19,134 MW	Sep 10, 2020	18:00 (ending)

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

Procedure	Declared	Cancelled	Note
None in September			

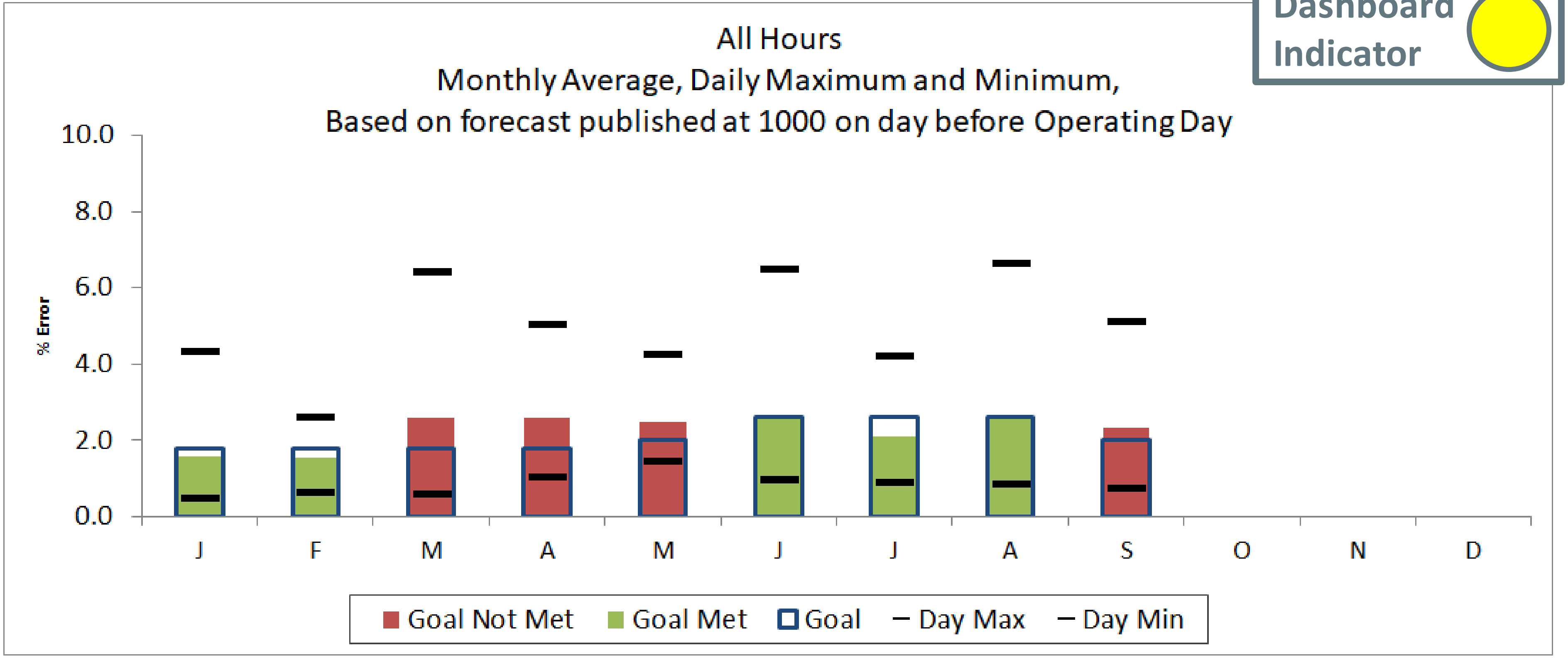
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
9/6	IESO	520
9/8	NBPSO	350

2020 System Operations - Load Forecast Accuracy

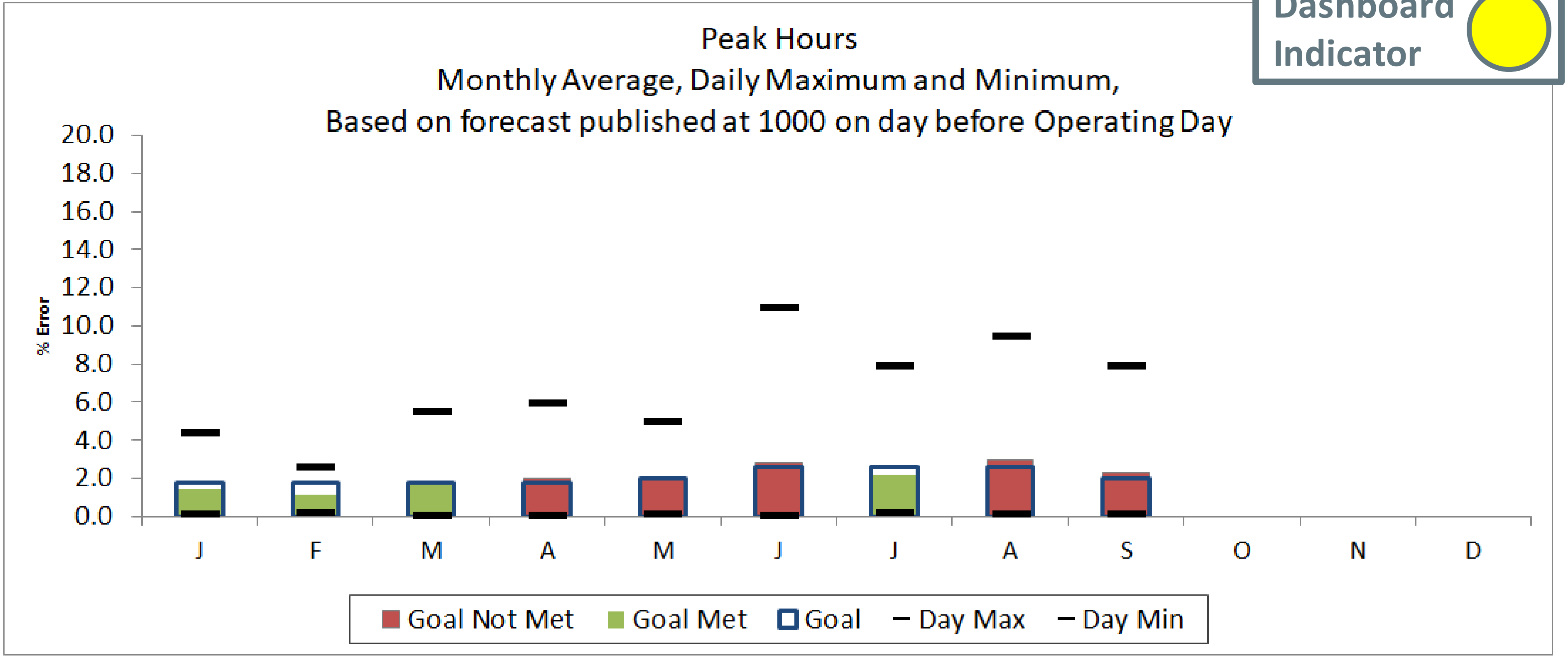
Dashboard Indicator 🟡



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				6.63
Day Min	0.46	0.61	0.58	1.03	1.42	0.96	0.88	0.84	0.72				0.46
MAPE	1.57	1.54	2.60	2.58	2.49	2.58	2.10	2.56	2.31				2.26
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00				

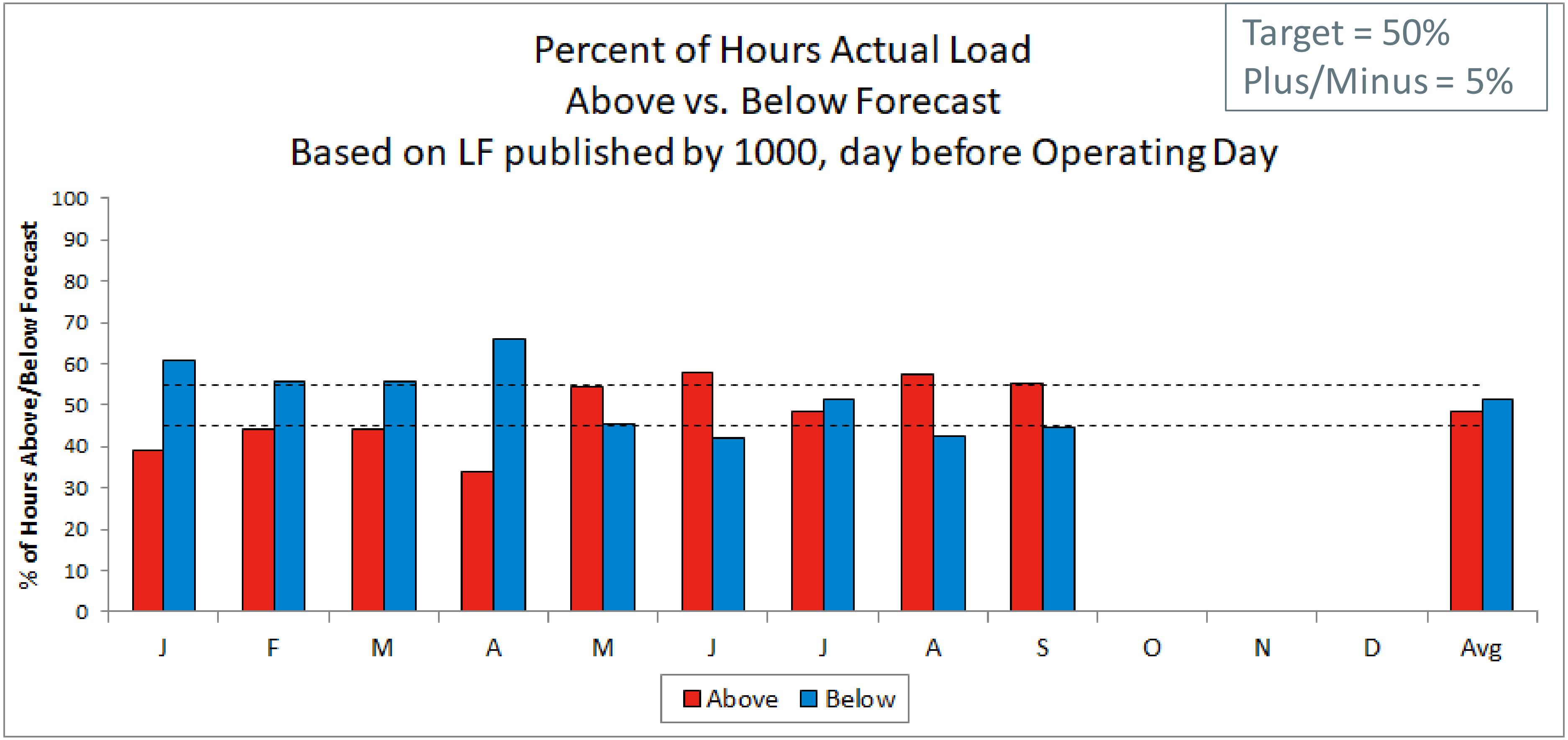
2020 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator 🟡


Peak Hours
Monthly Average, Daily Maximum and Minimum,
Based on forecast published at 1000 on day before Operating Day

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				10.93
Day Min	0.07	0.19	0.01	0.00	0.13	0.05	0.14	0.07	0.10				0.00
MAPE	1.41	1.12	1.72	1.97	2.11	2.83	2.18	2.97	2.29				2.07
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00				

2020 System Operations - Load Forecast Accuracy cont.

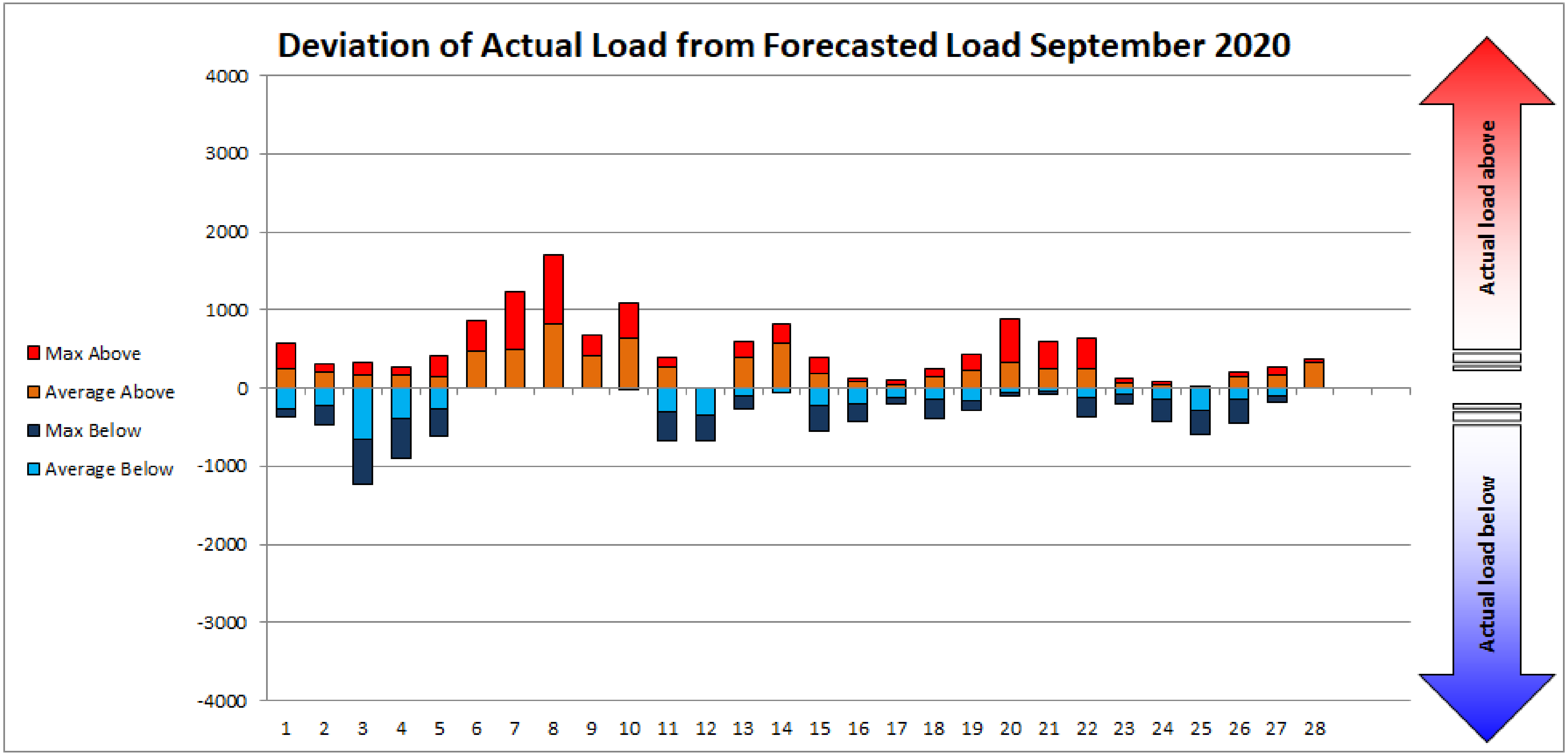


Percent of Hours Actual Load
Above vs. Below Forecast
Based on LF published by 1000, day before Operating Day

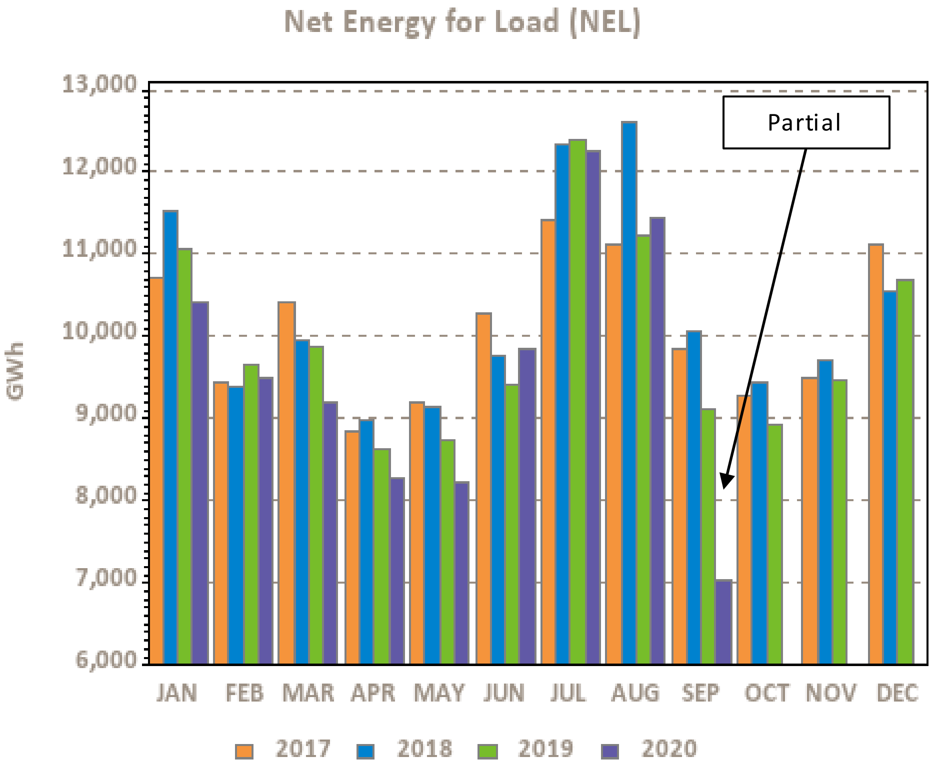
Target = 50%
Plus/Minus = 5%

	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	55.4				48
Below %	61	55.7	55.6	66.1	45.6	42.1	51.6	42.4	44.6				52
Avg Above	136.2	169.9	207	178.9	231.9	257.5	248.3	287.2	242.5				287
Avg Below	-192.4	-157.6	-263.9	-265.3	-196.3	-243.5	-281.7	-245.5	-148.3				-282
Avg All	-65	-13	-56	-106	38	22	-26	73	96				-4

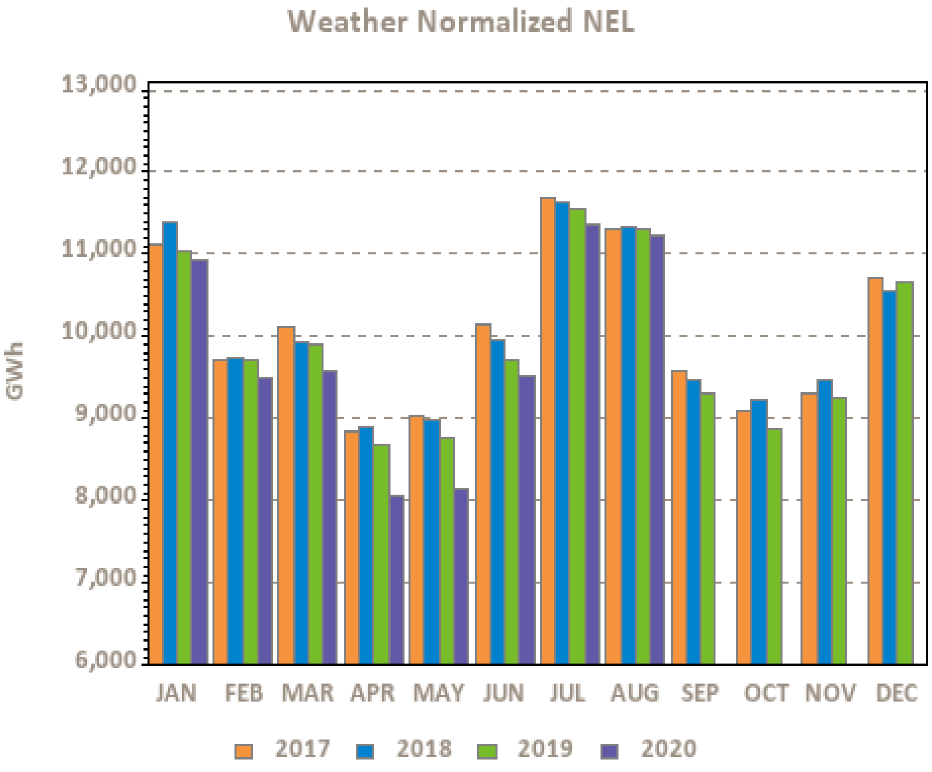
2020 System Operations - Load Forecast Accuracy cont.



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



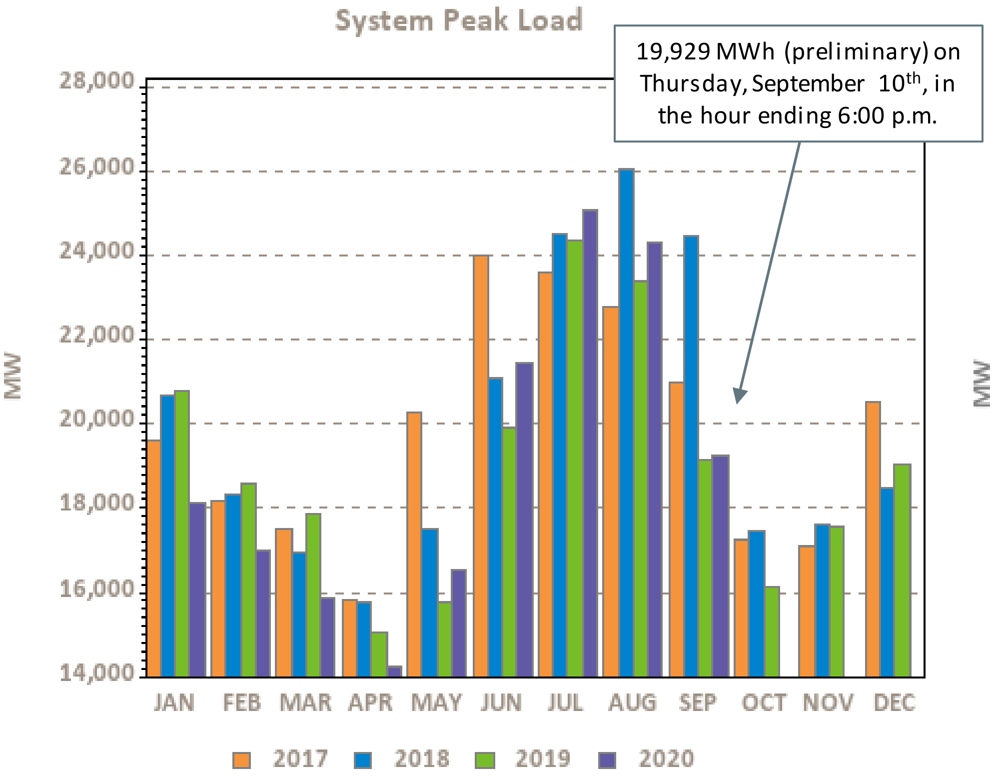
Ann Tot (TWh): 121.2 123.5 119.2 86.2



Ann Tot (TWh): 120.7 120.6 118.7 78.4

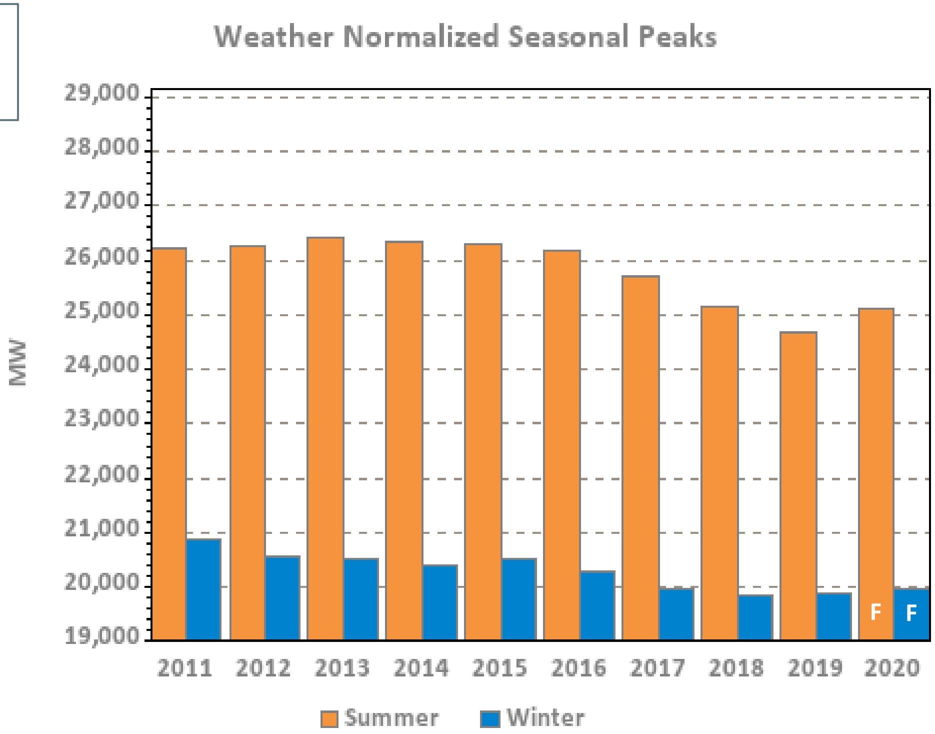
NEPOOL NEL is the total net revenue quality metered energy required to serve load and is analogous to 'RT system load.' NEL is calculated as: Generation – pumping load + net interchange where imports are positively signed. Current month's data may be preliminary. Weather normalized NEL may be reported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

Monthly Peak Loads and Weather Normalized Seasonal Peak History



19,929 MWh (preliminary) on Thursday, September 10th, in the hour ending 6:00 p.m.

Revenue quality metered value

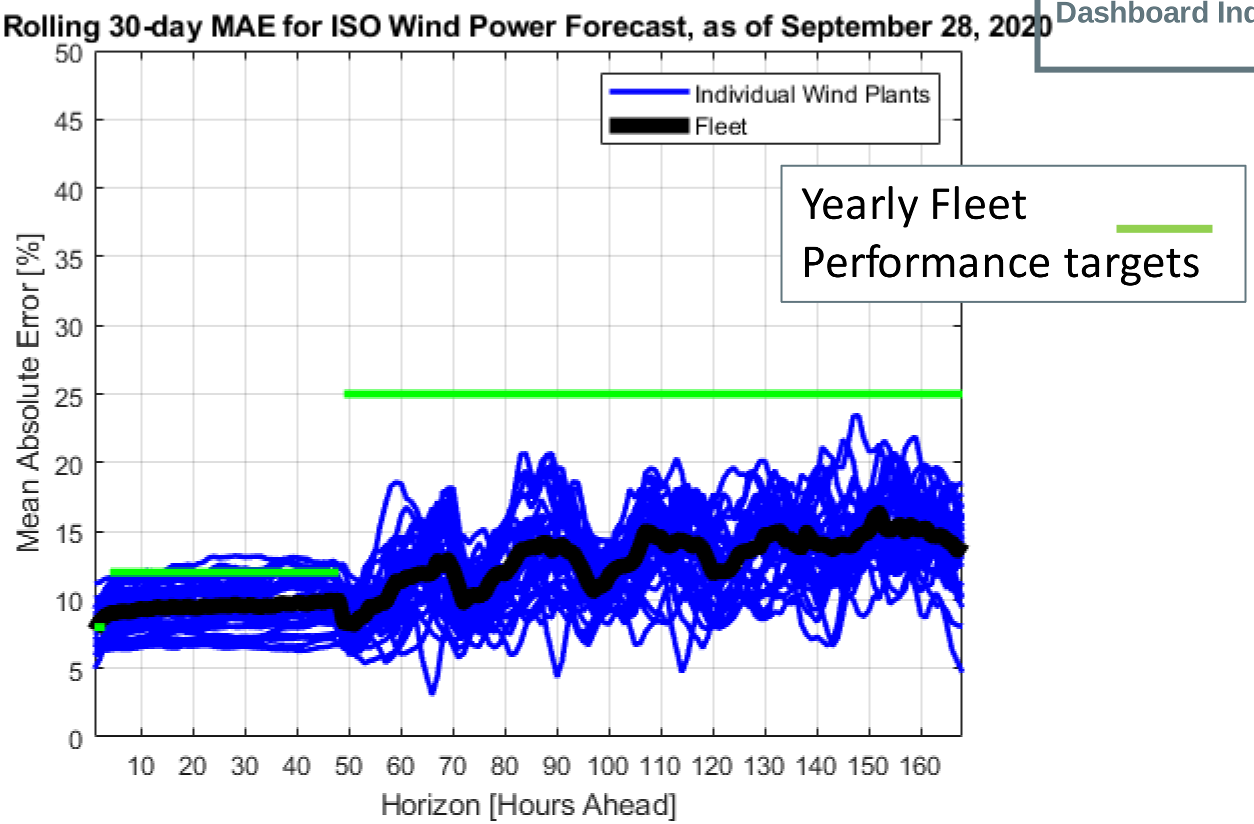


Winter beginning in year displayed

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

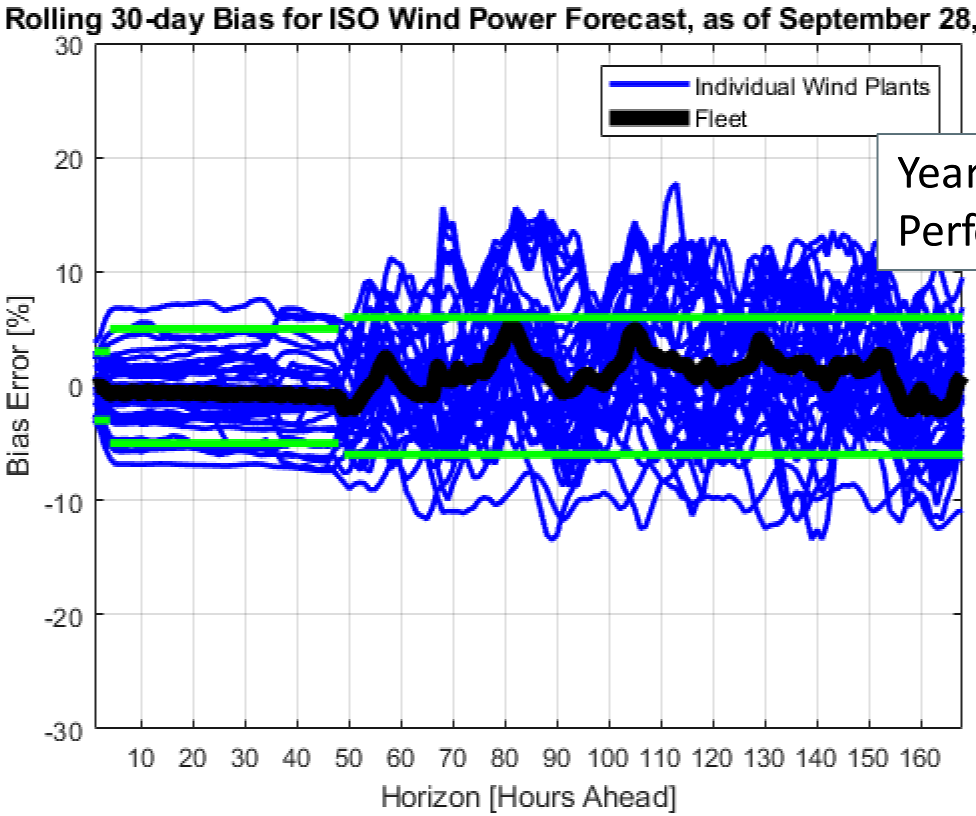
Dashboard Indicator ●



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 🟢

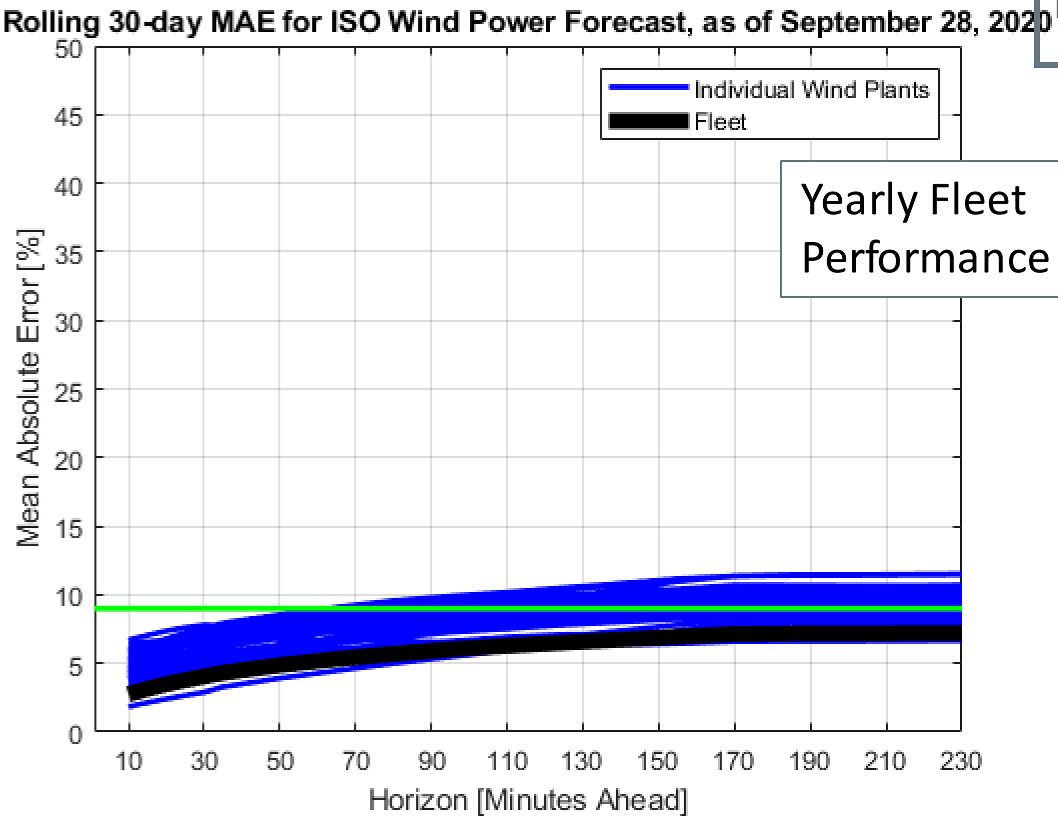


Yearly Fleet Performance targets 🟩

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



Yearly Fleet Performance targets

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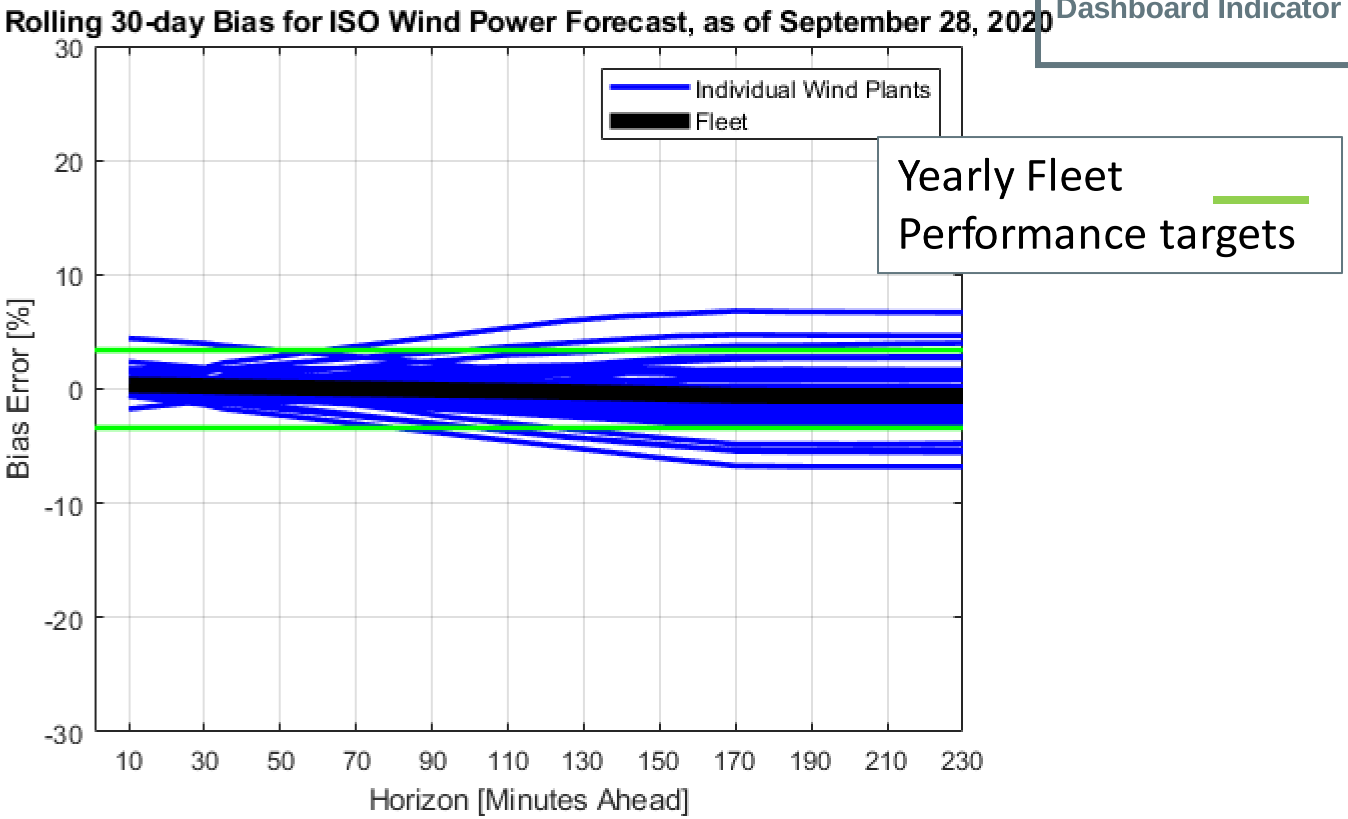
Wind Power Forecast Error Statistics: Short Term Forecast Bias

Dashboard Indicator ●

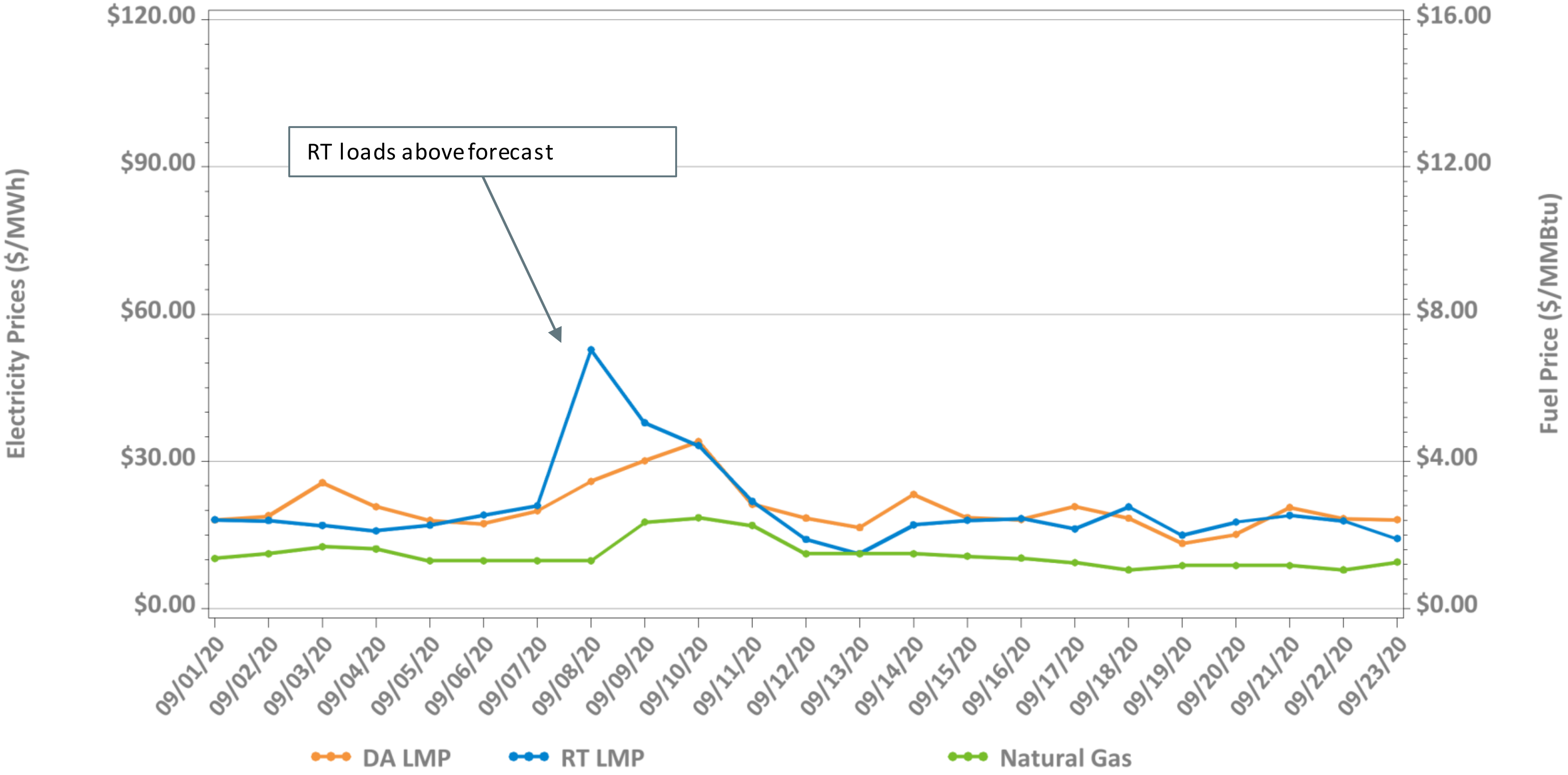


Yearly Fleet Performance targets

Ideally, MAE and Bias would be both equal to zero. Positive bias means less windpower was actually available compared to forecast. Negative bias means more windpower was actually available compared to forecast. Across all time frames, the ISO-NE/DNV-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: September 1-23, 2020



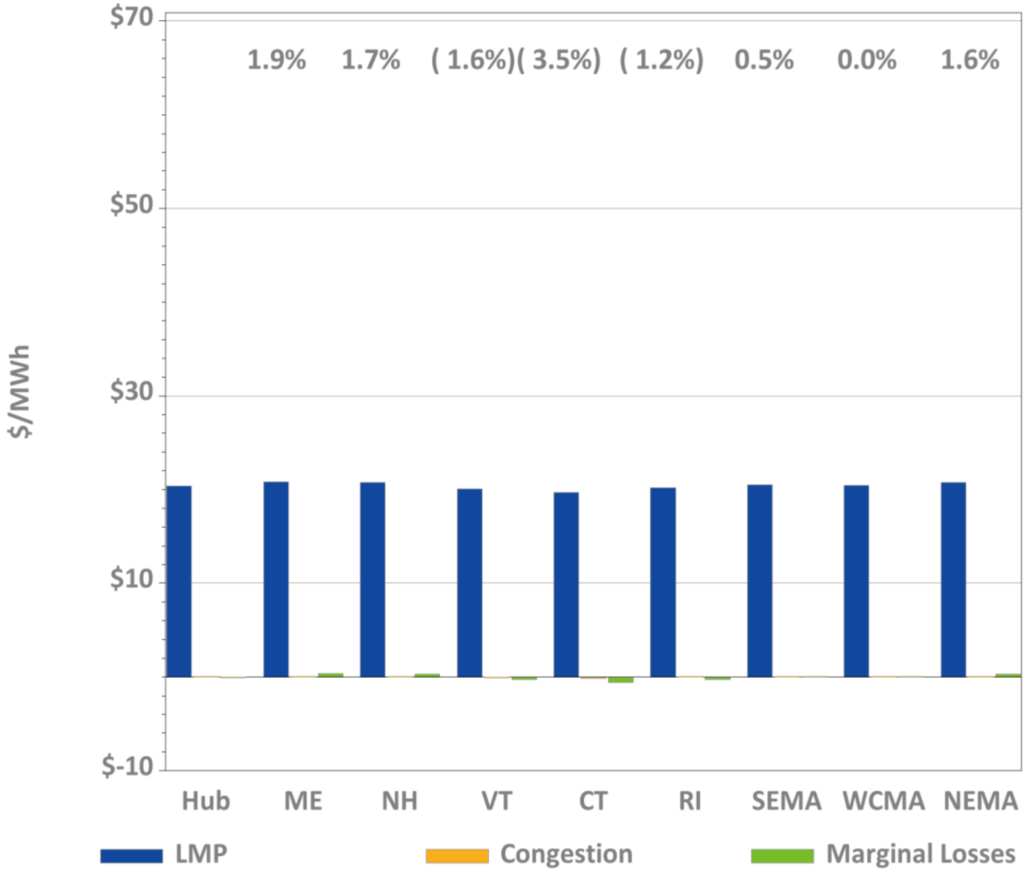
RT loads above forecast

Underlying natural gas data furnished by:

ice Global markets in clear view

Average price difference over this period (DA-RT): $-0.07
Average price difference over this period ABS(DA-RT): $3.81
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 19%
Gas price is average of Massachusetts delivery points

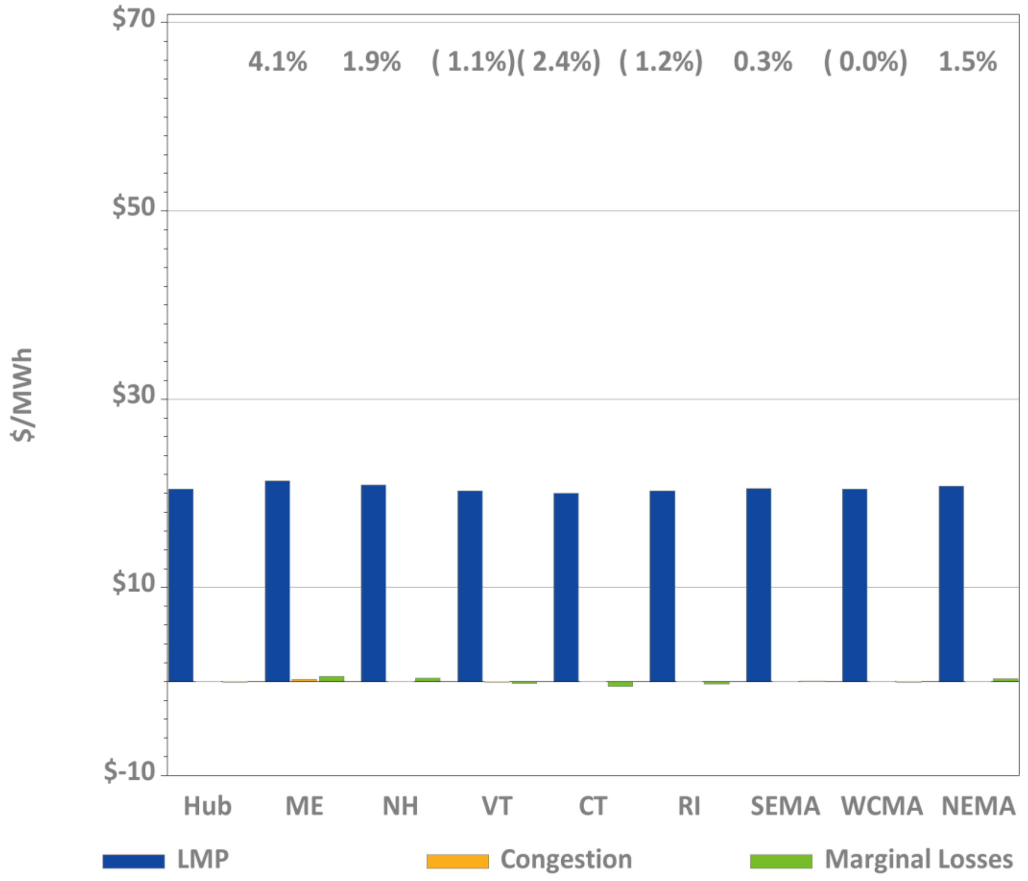
DA LMPs Average by Zone & Hub, September 2020



ME - Maine
NH – New Hampshire
VT – Vermont
CT – Connecticut

RI – Rhode Island
SEMA – Southeastern Massachusetts
WCMA – Western/Central Massachusetts
NEMA – Northeastern Massachusetts

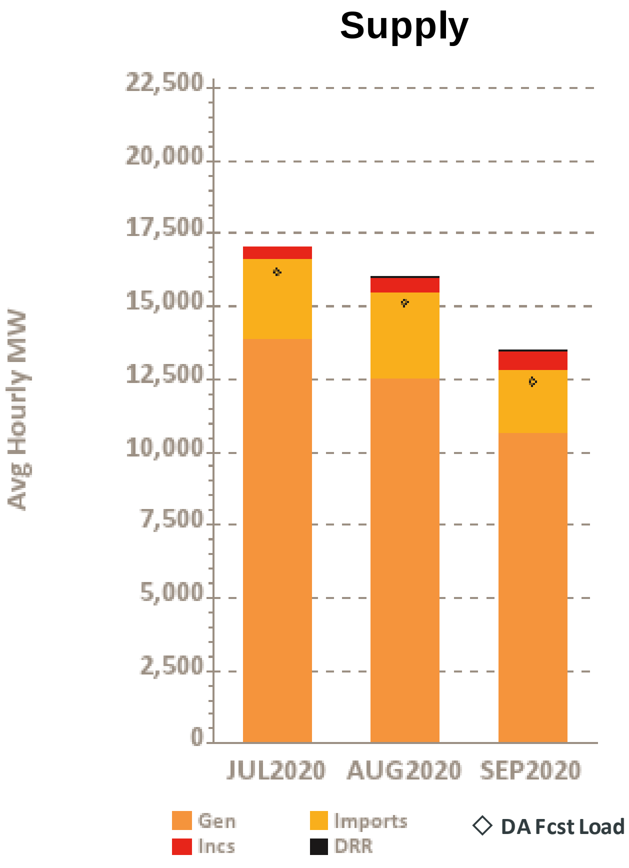
RT LMPs Average by Zone & Hub, September 2020

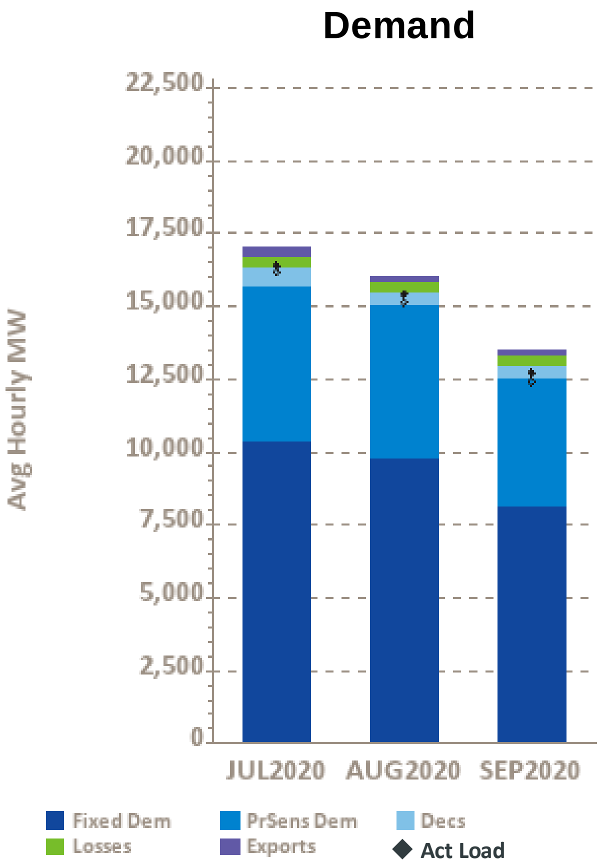


Definitions

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

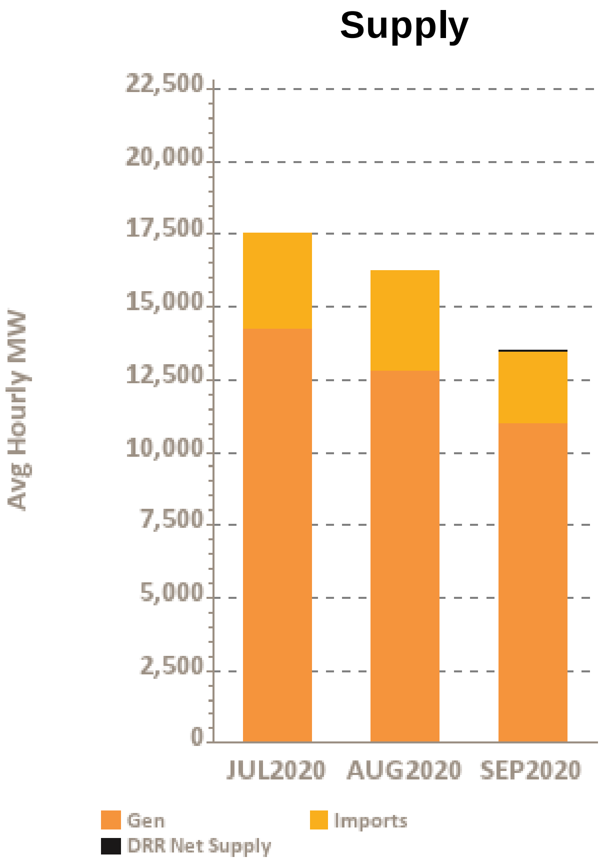


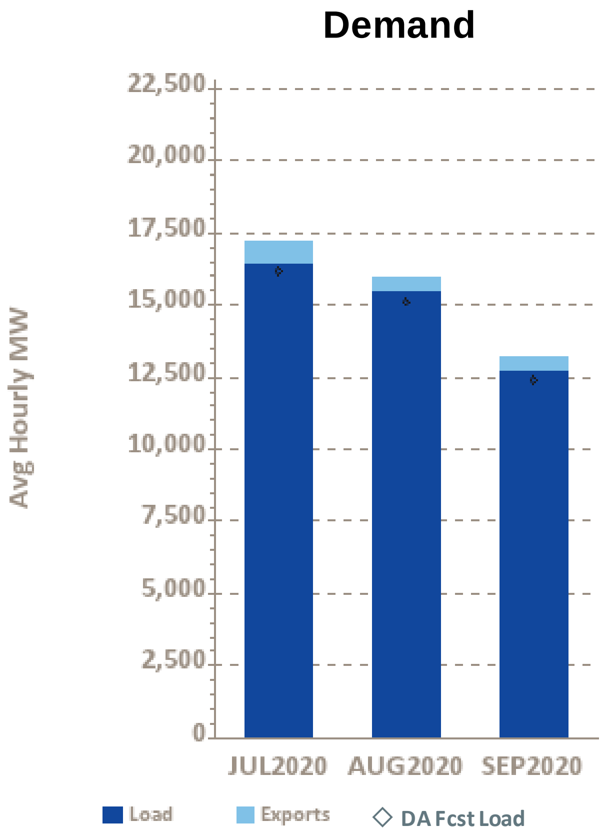


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load
DRR – Demand Response Resource

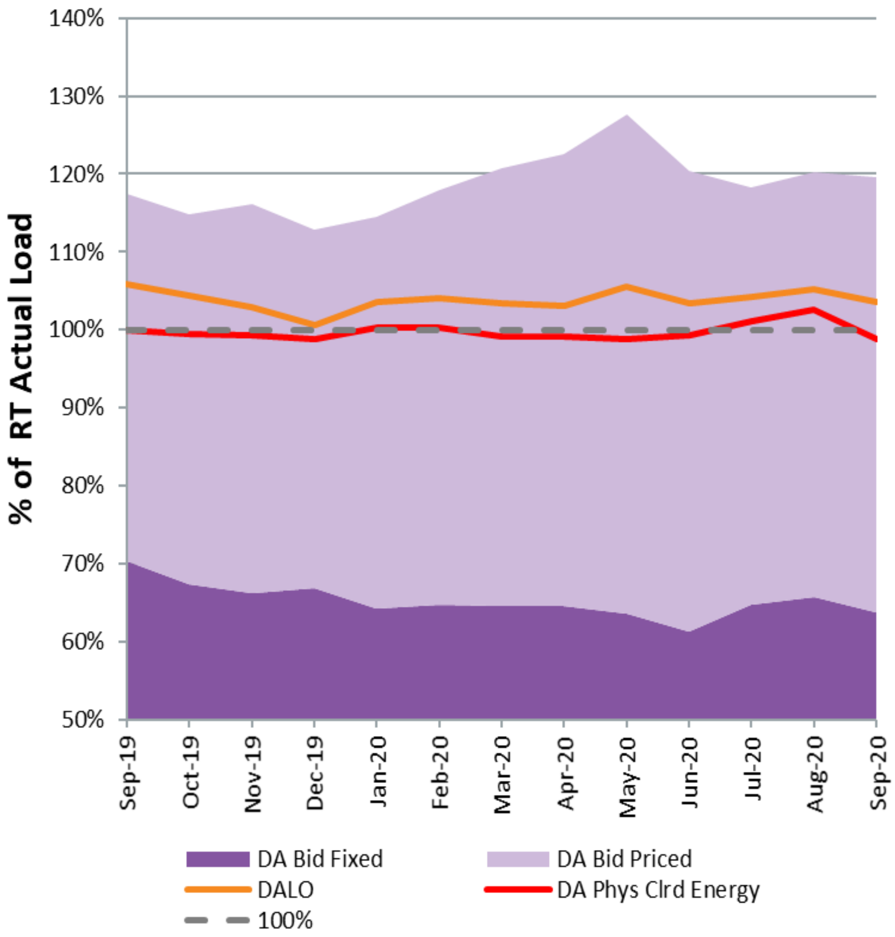
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

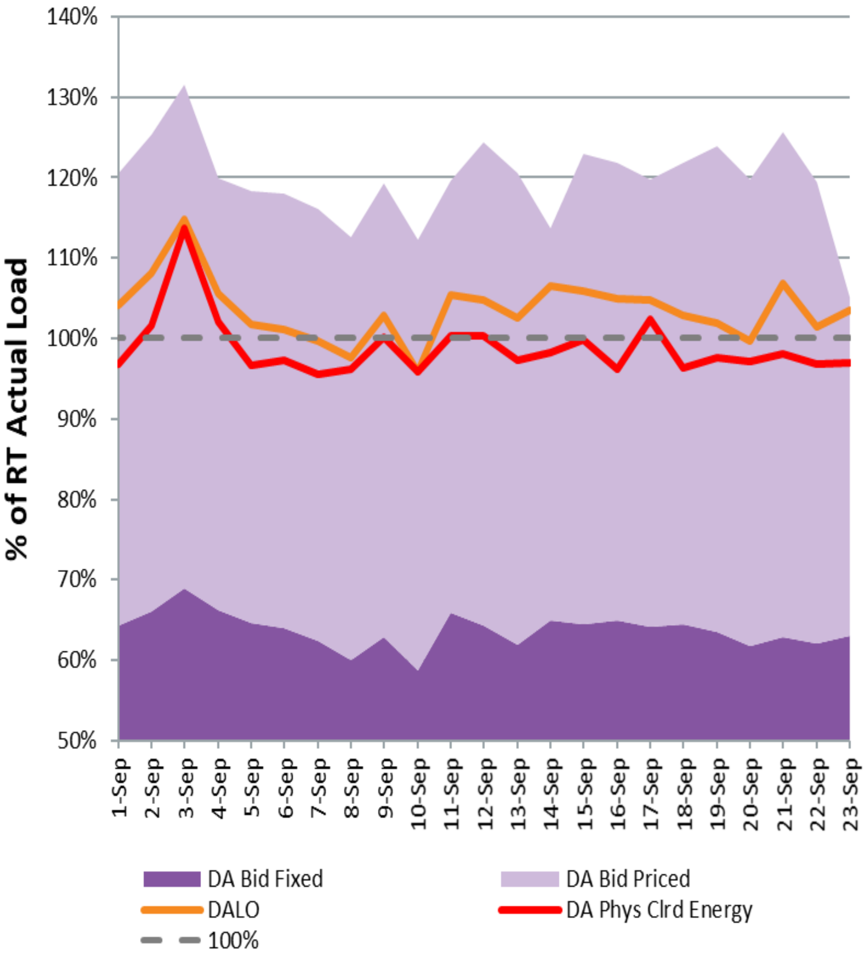
Components of RT Supply and Demand – Last Three Months





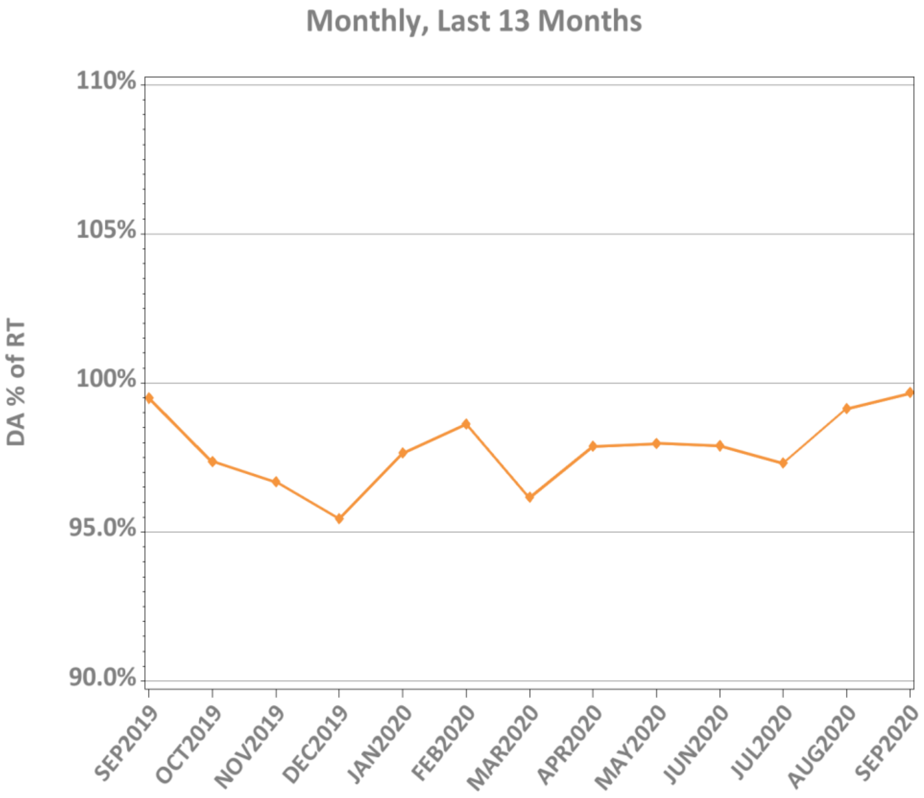
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

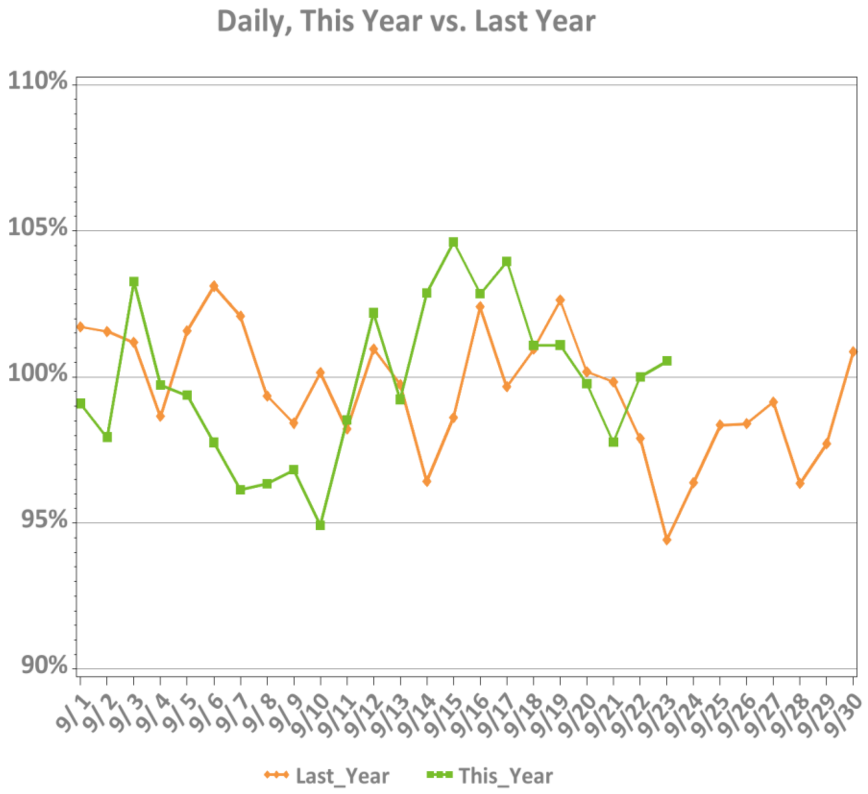




Note: Forecasted peak hour for each day is reflected in the above values. Shown for each day (chart on right) and then averaged for each month (chart on left). ‘DA Bid’ categories reflect load assets only (Virtual and export bids not reflected.)

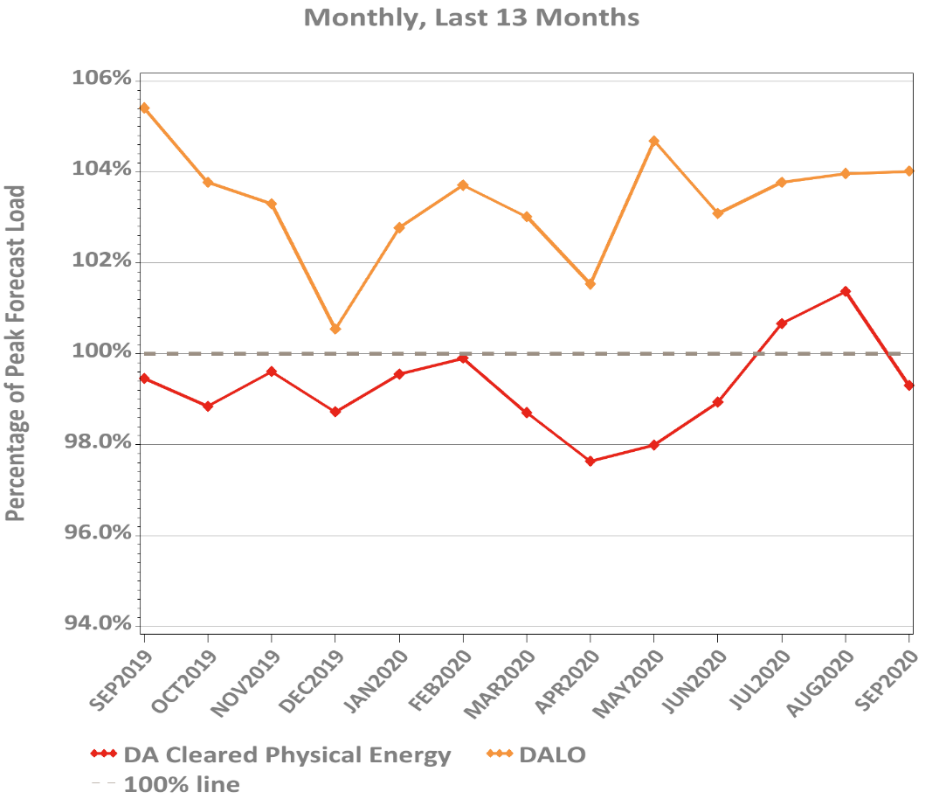
DA vs. RT Load Obligation: September, This Year vs. Last Year

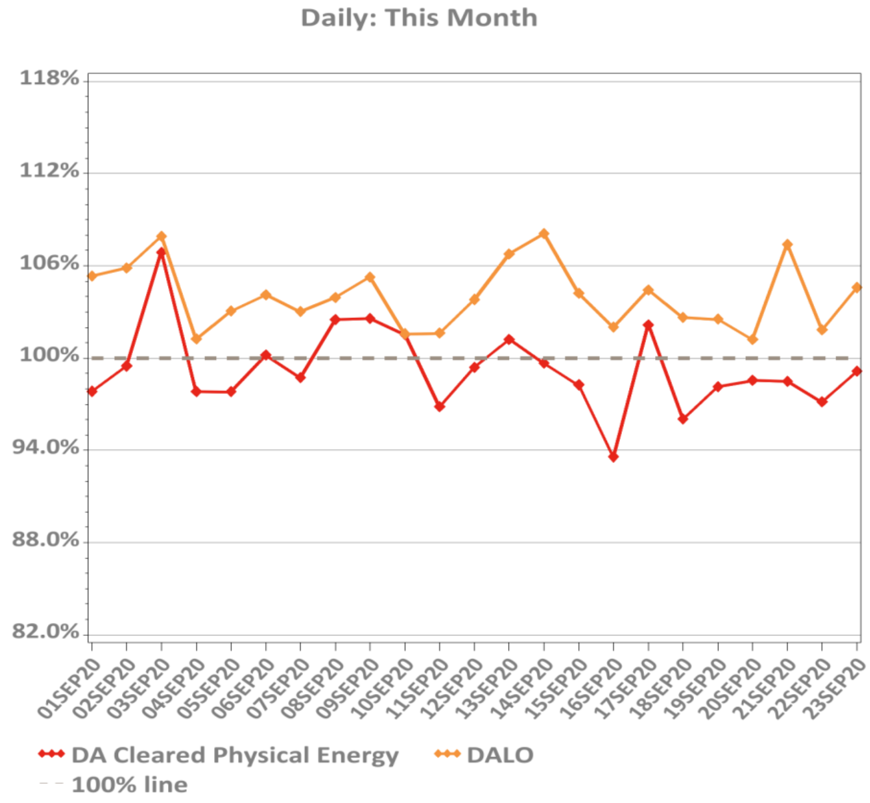




*Hourly average values

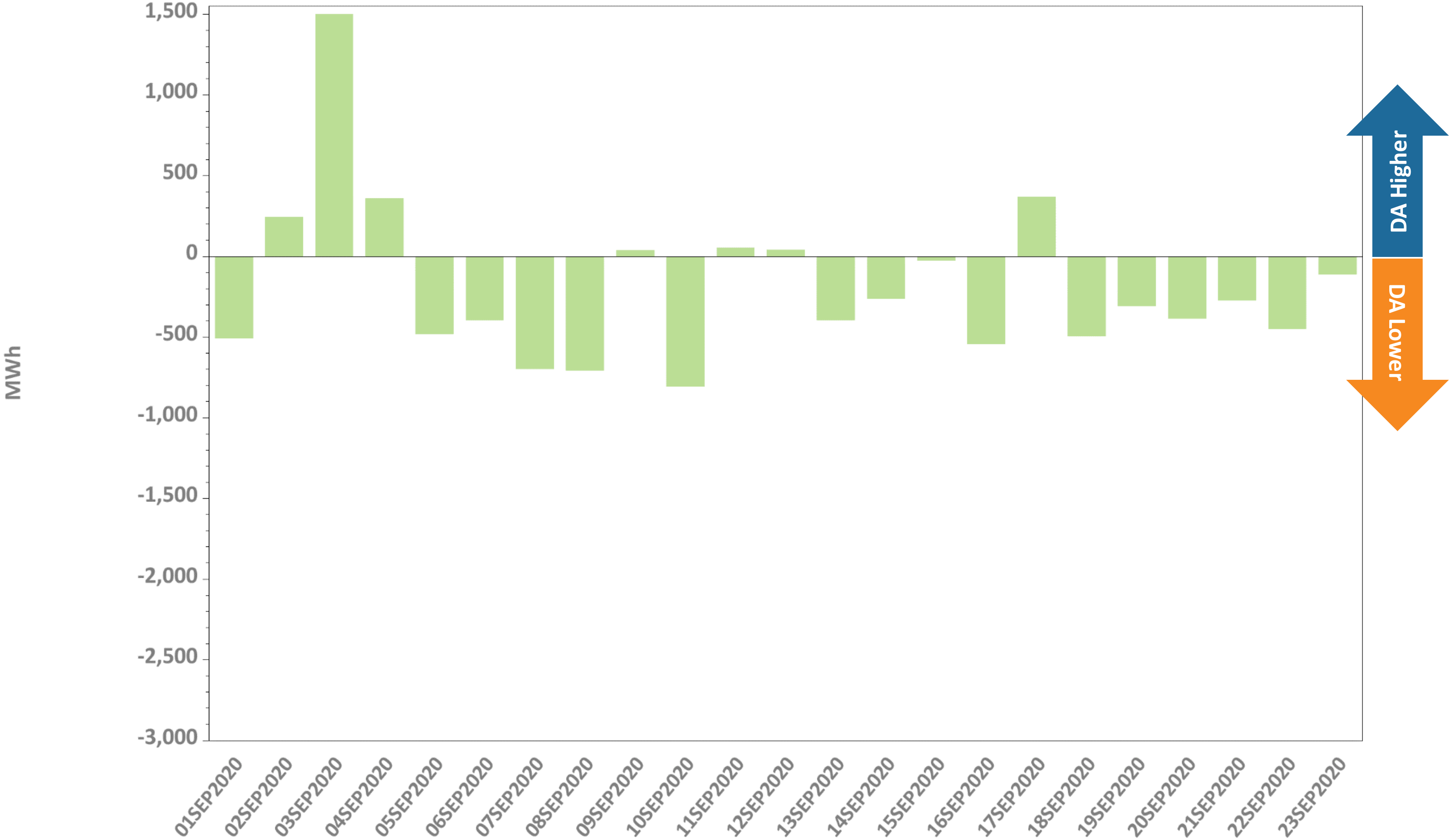
DA Volumes as % of Forecast in Peak Hour





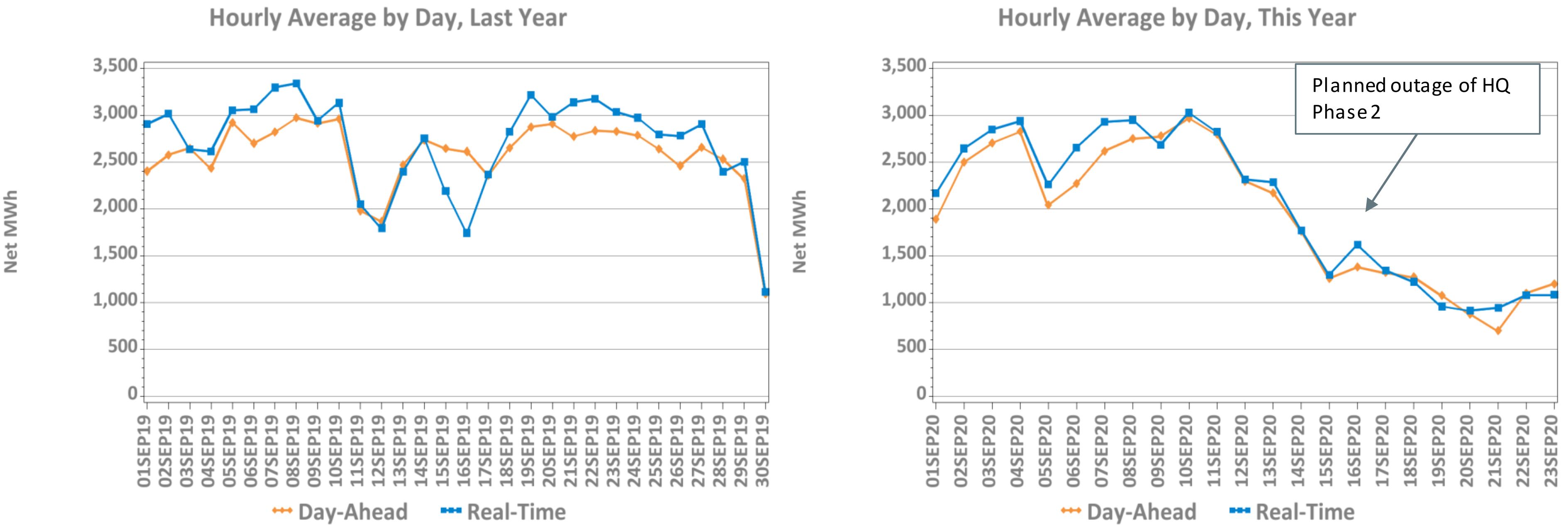
Note: There were no instances of system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) during September.

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.**

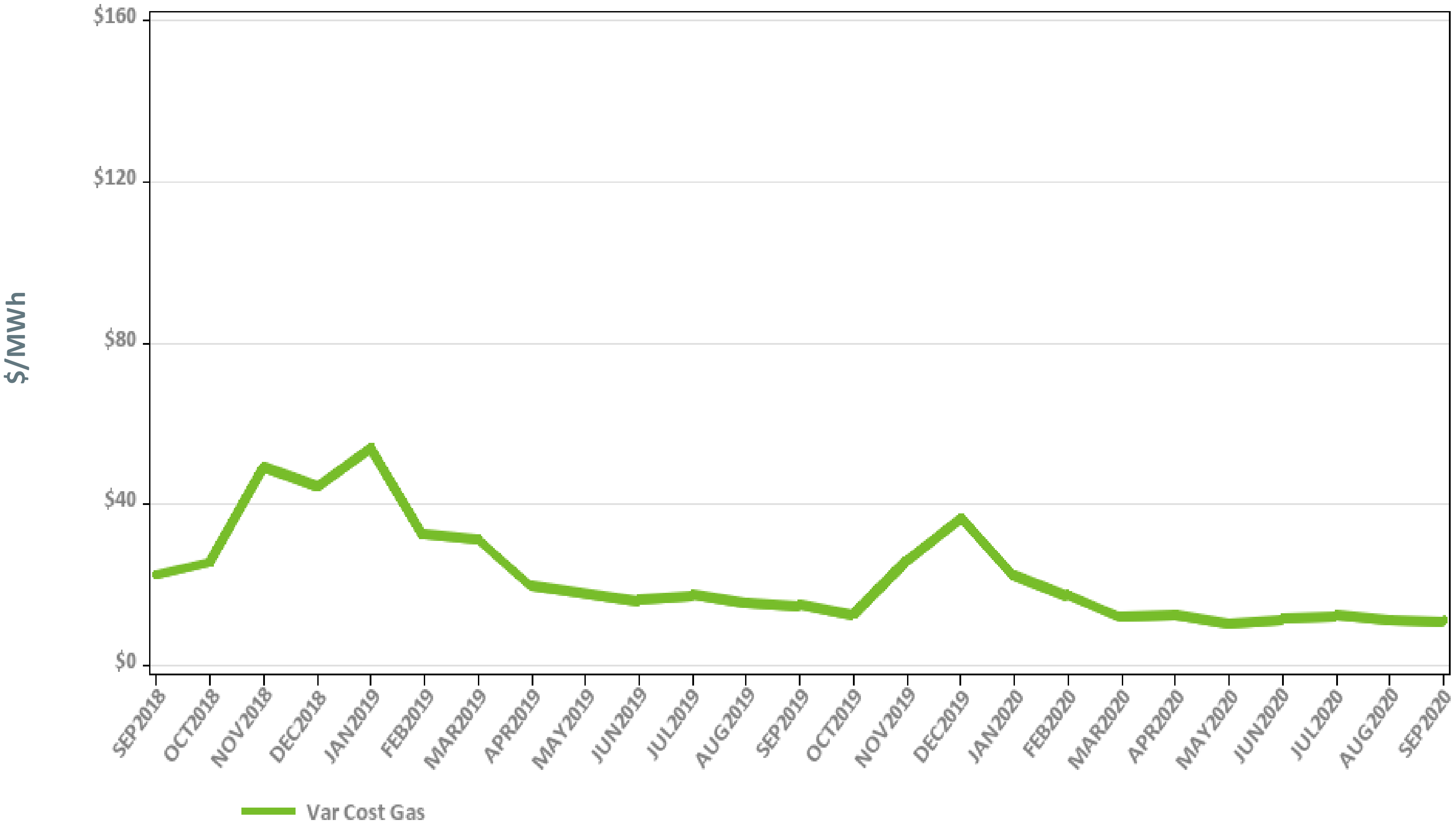
DA vs. RT Net Interchange September 2019 vs. September 2020



Planned outage of HQ Phase 2

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

Variable Production Cost of Natural Gas: Monthly

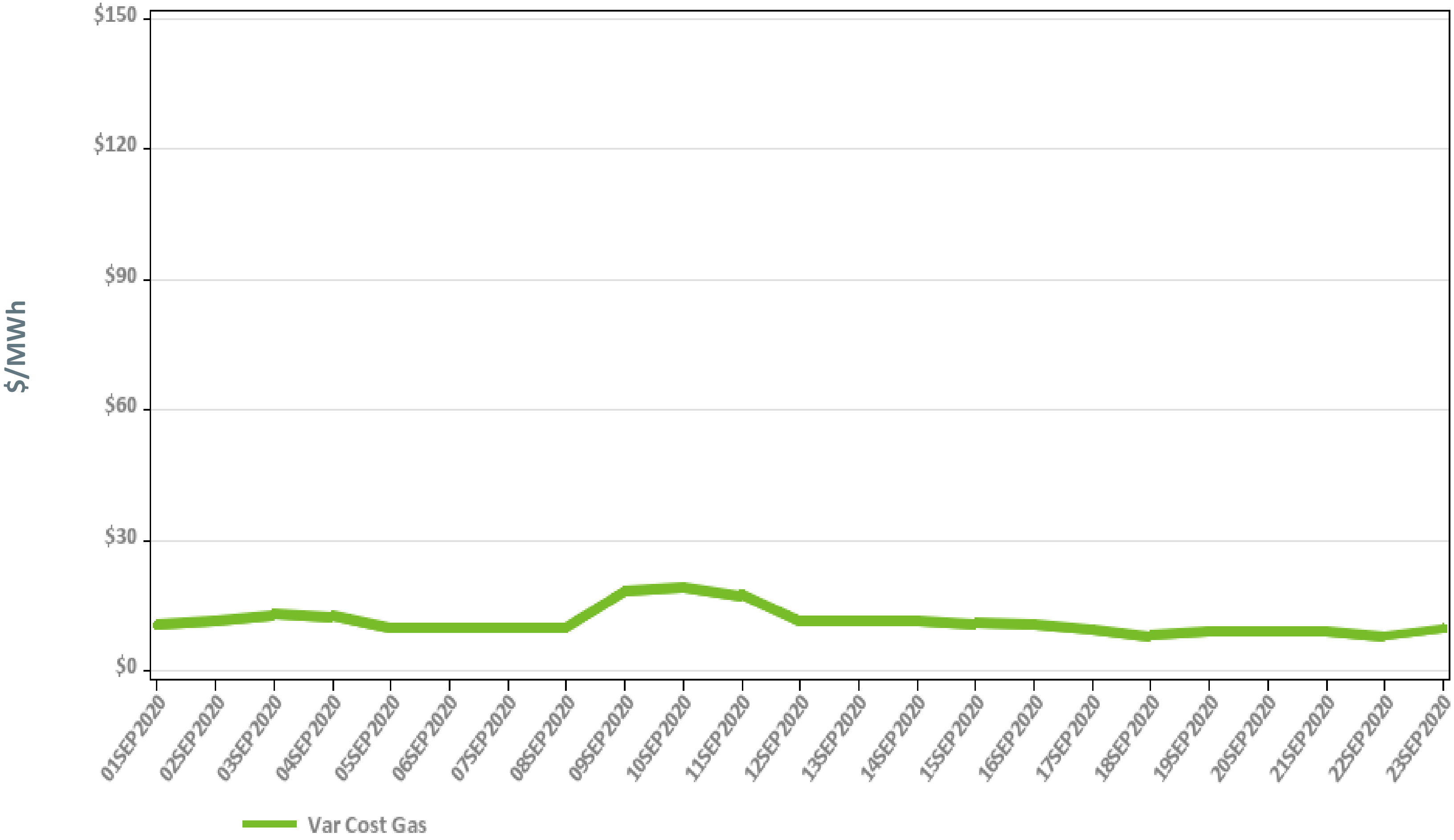


Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

Underlying natural gas data furnished by:

ICE Global markets in clear view

Variable Production Cost of Natural Gas: Daily

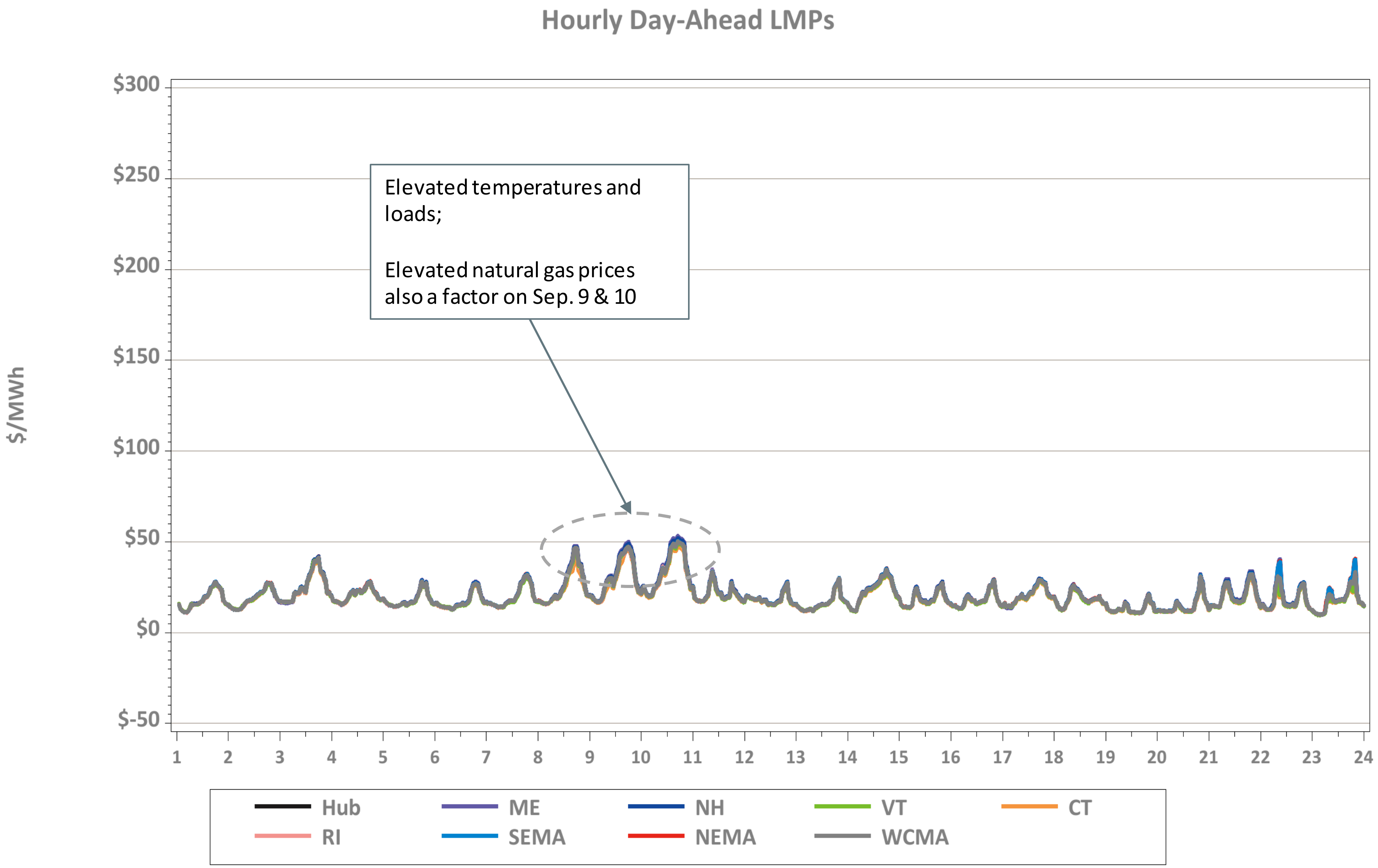


Underlying natural gas data furnished by:

ICE Global markets in clear view

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

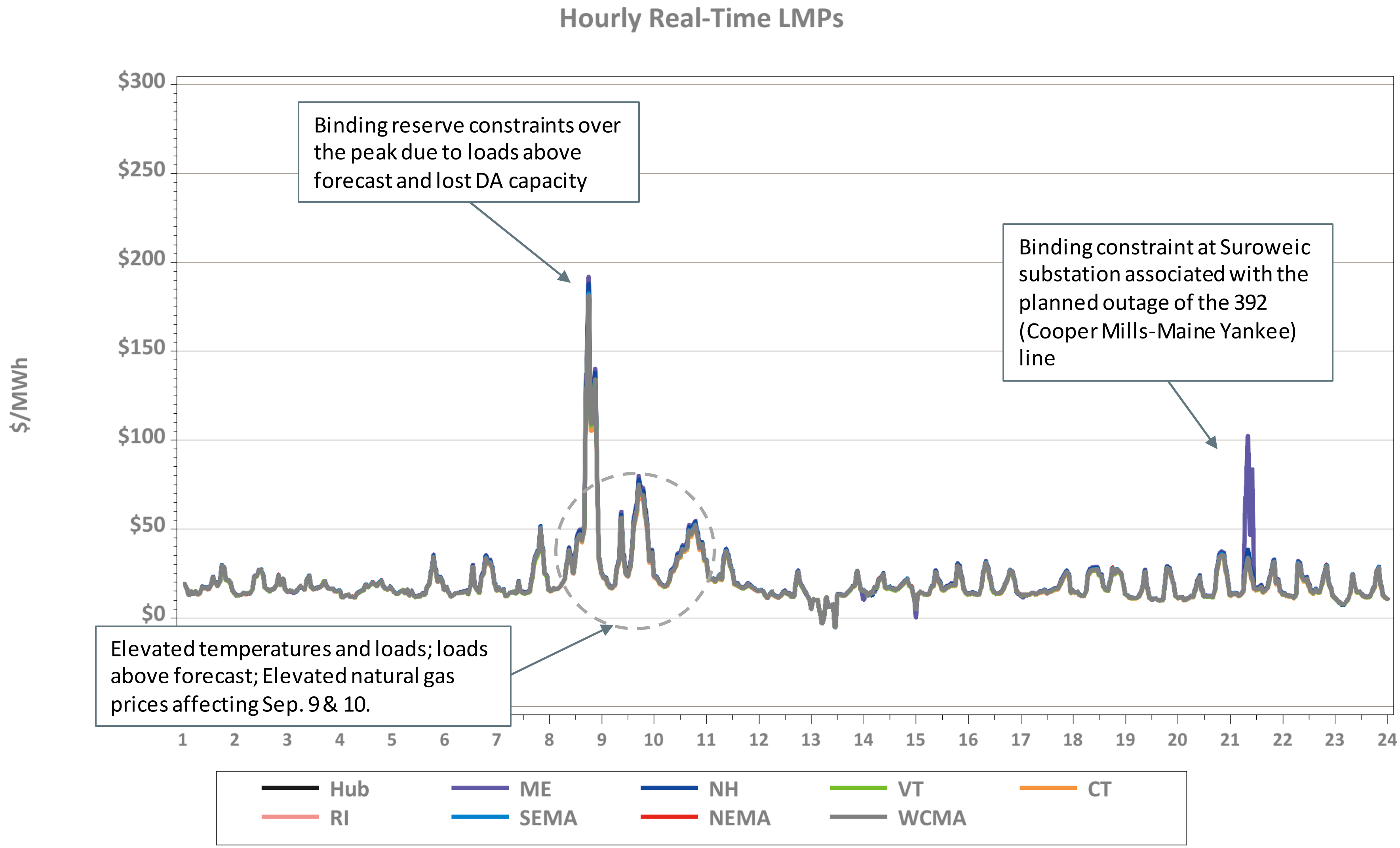
Hourly DA LMPs, September 1-23, 2020



Elevated temperatures and loads;

Elevated natural gas prices also a factor on Sep. 9 & 10

Hourly RT LMPs, September 1-23, 2020



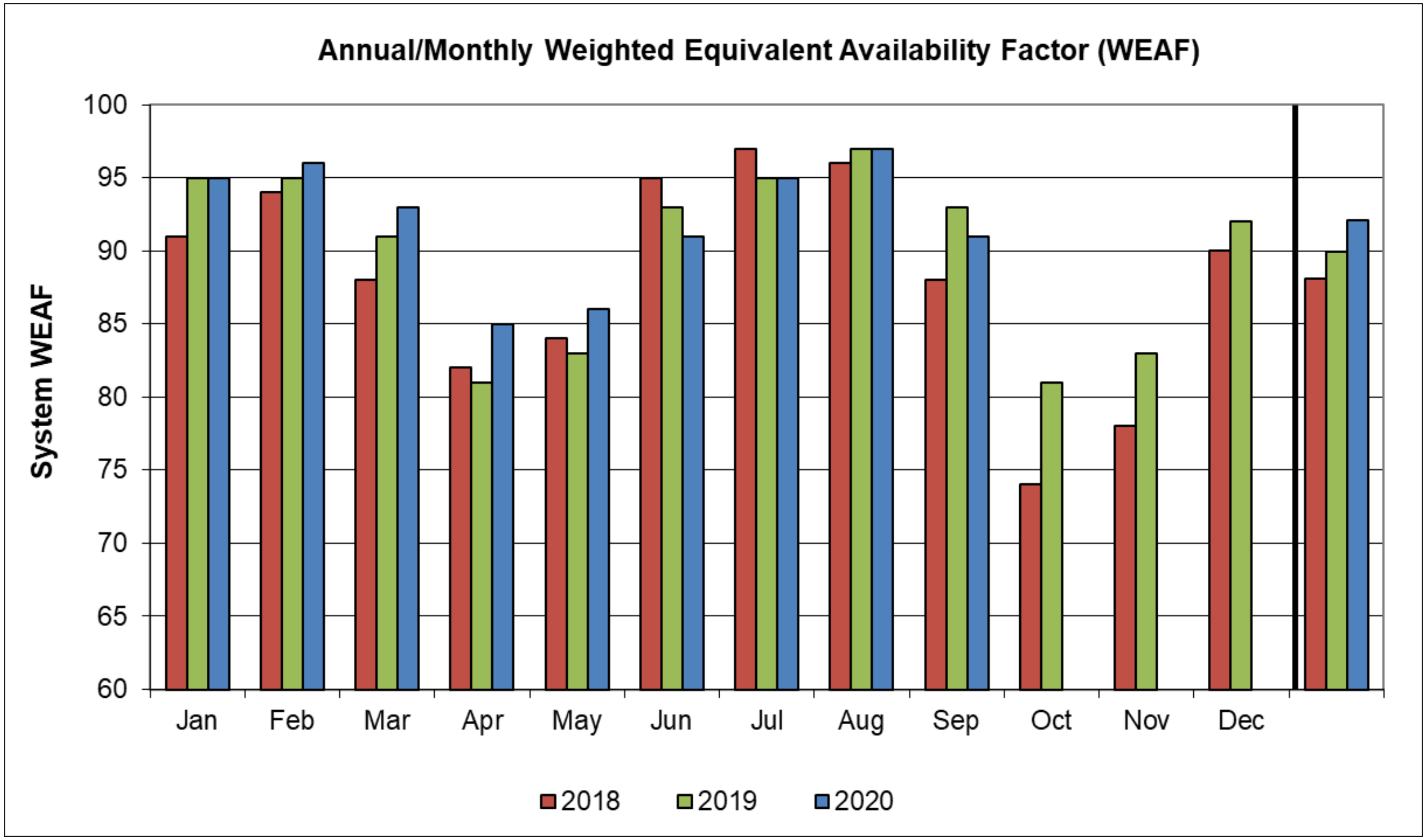
Binding reserve constraints over the peak due to loads above forecast and lost DA capacity

Binding constraint at Suroweic substation associated with the planned outage of the 392 (Cooper Mills-Maine Yankee) line

Elevated temperatures and loads; loads above forecast; Elevated natural gas prices affecting Sep. 9 & 10.

- No Minimum Generation Emergencies were declared during September.

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				92
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 9/22/2020

BACK-UP DETAIL

DEMAND RESPONSE

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

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	50.1	167.3	0.0	217.4
NH	31.9	149.0	0.0	180.9
VT	31.9	103.4	0.0	135.3
CT	106.1	165.3	549.2	820.6
RI	40.1	270.5	0.0	310.6
SEMA	45.0	446.6	0.0	491.6
WCMA	77.2	469.3	45.3	591.8
NEMA	61.3	812.2	0.0	873.6
Total	**443.6**	**2,583.7**	**594.5**	**3,621.7**

*** Active Demand Capacity Resources**

NOTE: CSO values include T&D loss factor (8%).

NEW GENERATION

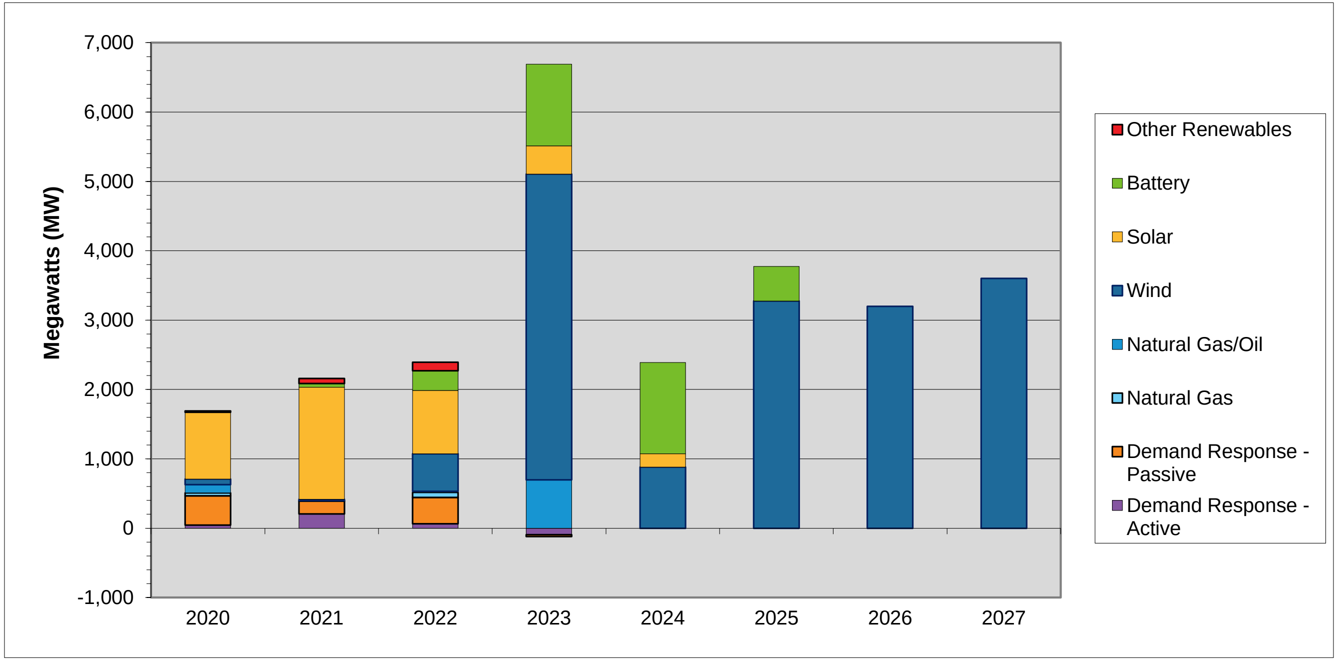
New Generation Update

Based on Queue as of 9/25/20

- Seven new projects totaling 4,252 MW applied for interconnection study since the last update
  - They consist of three new solar projects, three wind facilities, and one battery project, with in-service dates ranging from 2020 to 2027
- No projects went commercial and three were withdrawn, resulting in a net increase in new generation projects of 4,127 MW
- In total, 250 generation projects are currently being tracked by the ISO, totaling approximately 24,500 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



	2020	2021	2022	2023	2024	2025	2026	2027	Total MW	% of Total[1]
Other Renewables	18	73	122	0	0	0	0	0	213	0.8
Battery	0	54	284	1,175	1,316	500	0	0	3,329	12.9
Solar[2]	964	1,614	914	408	191	0	0	0	4,091	15.9
Wind	78	19	540	4,411	881	3,276	3,200	3,600	16,005	62.1
Natural Gas/Oil[3]	121	0	16	695	0	0	0	0	832	3.2
Natural Gas	43	10	73	0	0	0	0	0	126	0.5
Demand Response - Passive	422	184	380	-28	0	0	0	0	958	3.7
Demand Response - Active	42	204	62	-94	0	0	0	0	214	0.8
Totals	**1,689**	**2,158**	**2,391**	**6,567**	**2,388**	**3,776**	**3,200**	**3,600**	**25,769**	**100.0**

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

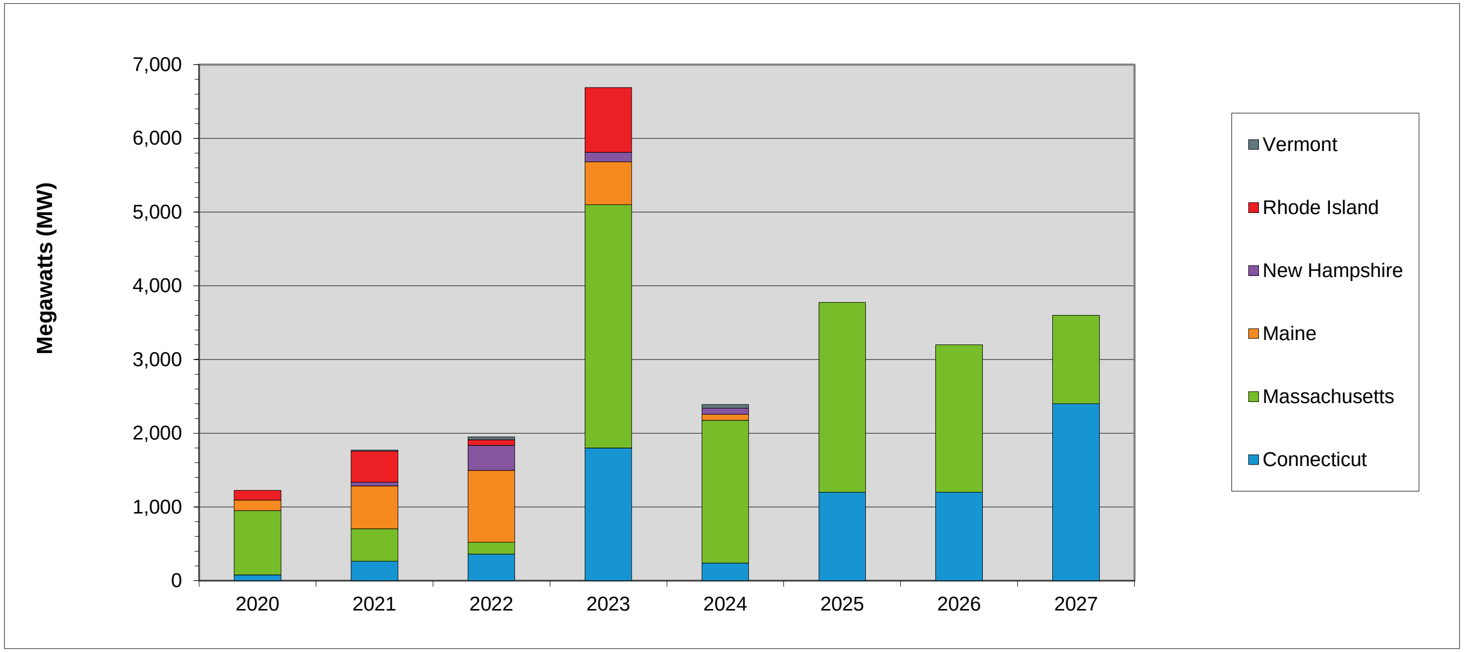
[2] This category includes both solar-only, and co-located solar and battery projects

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

- 2020 values include the 83 MW of generation that has gone commercial in 2020
- DR reflects changes from the initial FCM Capacity Supply Obligations in 2010-11

Actual and Projected Annual Generator Capacity Additions

By State



	2020	2021	2022	2023	2024	2025	2026	2027	Total MW	% of Total[1]
Vermont	0	15	40	0	50	0	0	0	105	0.4
Rhode Island	133	421	73	880	0	0	0	0	1,507	6.1
New Hampshire	0	50	340	126	81	0	0	0	597	2.4
Maine	141	579	975	583	81	0	0	0	2,359	9.6
Massachusetts	873	440	159	3,300	1,936	2,576	2,000	1,200	12,484	50.8
Connecticut	77	265	362	1,800	240	1,200	1,200	2,400	7,544	30.7
Totals	**1,224**	**1,770**	**1,949**	**6,689**	**2,388**	**3,776**	**3,200**	**3,600**	**24,596**	**100.0**

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

- 2020 values include the 83 MW of generation that has gone commercial in 2020

New Generation Projection

By Fuel Type

	Total		Green		Yellow	
Unit Type	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**
Biomass/Wood Waste	1	8	0	0	1	8
Battery Storage	18	3,329	0	0	18	3,329
Fuel Cell	5	69	1	10	4	59
Hydro	3	99	1	66	2	33
Natural Gas	7	126	0	0	7	126
Natural Gas/Oil	5	787	1	14	4	773
Nuclear	1	37	0	0	1	37
Solar	185	4,058	9	175	176	3,883
Wind	25	16,000	2	88	23	15,912
Total	250	24,513	14	353	236	24,160

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

New Generation Projection

By Operating Type

	Total		Green		Yellow	
Operating Type	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	9	147	1	10	8	137
Intermediate	9	822	1	14	8	808
Peaker	207	7,544	10	241	197	7,303
Wind Turbine	25	16,000	2	88	23	15,912
Total	250	24,513	14	353	236	24,160

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

New Generation Projection

By Operating Type and Fuel Type

	Total		Baseload		Intermediate		Peaker		Wind Turbine	
Unit Type	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**
Biomass/Wood Waste	1	8	1	8	0	0	0	0	0	0
Battery Storage	18	3,329	0	0	0	0	18	3,329	0	0
Fuel Cell	5	69	5	69	0	0	0	0	0	0
Hydro	3	99	2	33	0	0	1	66	0	0
Natural Gas	7	126	0	0	6	120	1	6	0	0
Natural Gas/Oil	5	787	0	0	3	702	2	85	0	0
Nuclear	1	37	1	37	0	0	0	0	0	0
Solar	185	4,058	0	0	0	0	185	4,058	0	0
Wind	25	16,000	0	0	0	0	0	0	25	16,000
Total	250	24,513	9	147	9	822	207	7,544	25	16,000

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

FORWARD CAPACITY MARKET

Capacity Supply Obligation FCA 11

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		*CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	419.928	441.221	21.293	594.551	153.33	584.35	-10.201
	Passive Demand	2,791.02	2,835.354	44.334	2,883.767	48.413	2,964.695	80.928
Demand Total		**3,210.95**	**3,276.575**	**65.625**	**3,478.318**	**201.743**	**3,549.045**	**70.727**
Generator	*Non-Intermittent*	30,494.80	30,064.23	-430.569	30,159.891	95.661	2,9678.995	-480.896
	Intermittent	894.217	823.796	-70.421	809.571	-14.225	689.524	-120.047
Generator Total		**31,389.02**	**30,888.027**	**-500.993**	**30,969.462**	**81.435**	**30,368.519**	**-600.943**
Import Total		**1,235.40**	**1,622.037**	**386.637**	**1,609.844**	**-12.193**	**1,124.6**	**-485.244**
****Grand Total**		**35,835.37**	**35,786.64**	**-48.731**	**36,057.624**	**270.984**	**35,042.164**	**-1015.46**
Net ICR (NICR)		**34,075**	**33,660**	**-415**	**33,520**	**-140**	**32,205**	**-1,315**

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

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

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

Capacity Supply Obligation FCA 12

Resource Type	Resource Type				ARA 2		ARA 3	
		*CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	624.445	659.137	34.692	603.776	-55.361		
	Passive Demand	2,975.36	3,045.073	69.713	31,23.232	78.159		
Demand Total		**3,599.81**	**3,704.21**	**104.4**	**37,27.008**	**22.798**		
Generator	*Non-Intermittent*	29,130.75	29,244.404	113.654	28,620.245	-624.159		
	Intermittent	880.317	806.609	-73.708	660.932	-145.677		
Generator Total		**30,011.07**	**30,051.013**	**39.943**	**29,281.177**	**-769.836**		
Import Total		**1,217**	**1,305.487**	**88.487**	**1,307.587**	**2.10**		
****Grand Total**		**34,827.88**	**35,060.710**	**232.83**	**34,315.772**	**-744.94**		
Net ICR (NICR)		**33,725**	**33,550**	**-175**	**32,320**	**-230**		

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

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

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

Capacity Supply Obligation FCA 13

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		*CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	685.554	683.116	-2.438				
	Passive Demand	3,354.69	3,407.507	52.817				
Demand Total		**4,040.244**	**4,090.623**	**50.38**				
Generator	*Non-Intermittent*	28,586.498	27,868.341	-718.157				
	Intermittent	1,024.792	901.672	-123.12				
Generator Total		**2,9611.29**	**28,770.013**	**-841.28**				
Import Total		**1,187.69**	**1,292.41**	**104.72**				
****Grand Total**		**34,839.224**	**34,153.046**	**-686.18**				
Net ICR (NICR)		**33,750**	**32,465**	**-1,285**				

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

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

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

Capacity Supply Obligation FCA 14

Resource Type	**Resource Type**	**FCA**	**ARA 1**		**ARA 2**		**ARA 3**	
		***CSO**	**CSO**	**Change**	**CSO**	**Change**	**CSO**	**Change**
		MW	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**
Demand	*Active Demand*	592.043						
	Passive Demand	3,327.071						
Demand Total		**3,919.114**						
Generator	*Non-Intermittent*	27,816.902						
	Intermittent	1,160.916						
Generator Total		**28,977.818**						
Import Total		**1,058.72**						
****Grand Total**		**33,955.652**						
Net ICR (NICR)		**32,490**						

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

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

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

Active/Passive Demand Response

CSO Totals by Commitment Period

Commitment Period	Active/Passive	Existing	New	**Grand Total**
2019-20	Active	357.221	20.304	**377.525**
	Passive	2,018.20	350.43	**2,368.63**
	Grand Total	2375.422	370.734	**2746.156**
2020-21	Active	334.634	85.294	**419.928**
	Passive	2,236.73	554.292	**2,791.02**
	Grand Total	2571.361	639.586	**3210.947**
2021-22	Active	480.941	143.504	**624.445**
	Passive	2,604.79	370.568	**2,975.36**
	Grand Total	3085.734	514.072	**3599.806**
2022-23	Active	598.376	87.178	**685.554**
	Passive	2,788.33	566.363	**3,354.69**
	Grand Total	3386.703	653.541	**4040.244**
2023-24	Active	560.55	31.493	**592.043**
	Passive	3,035.51	291.565	**3,327.07**
	Grand Total	3596.056	323.058	**3919.114**

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

What are Daily NCPC Payments?

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

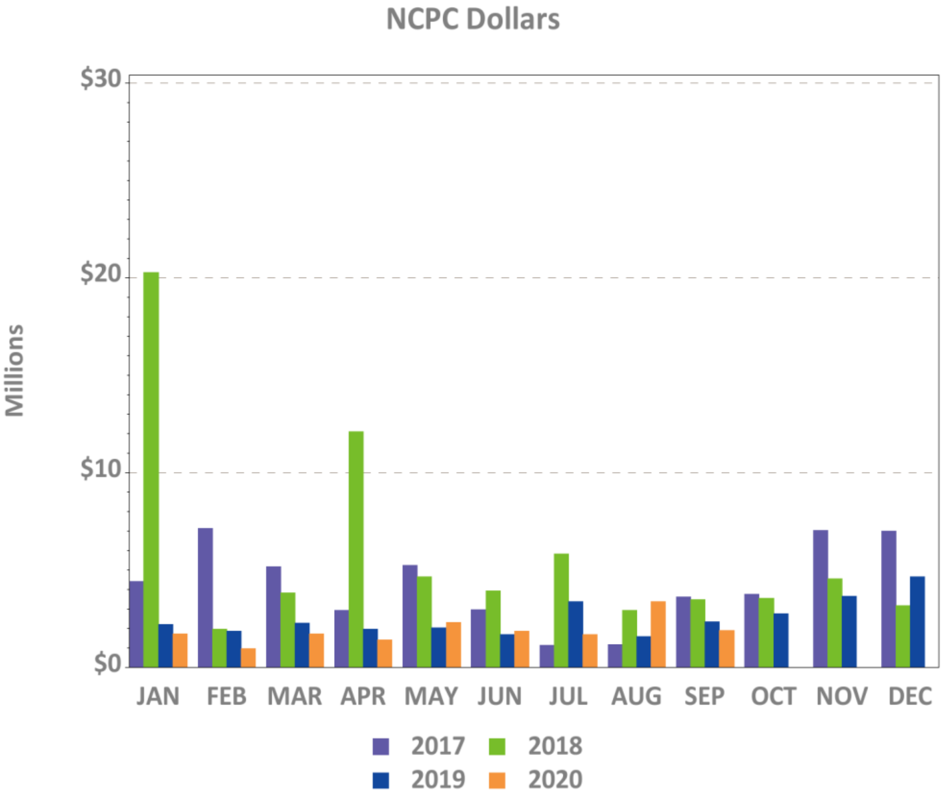
Definitions

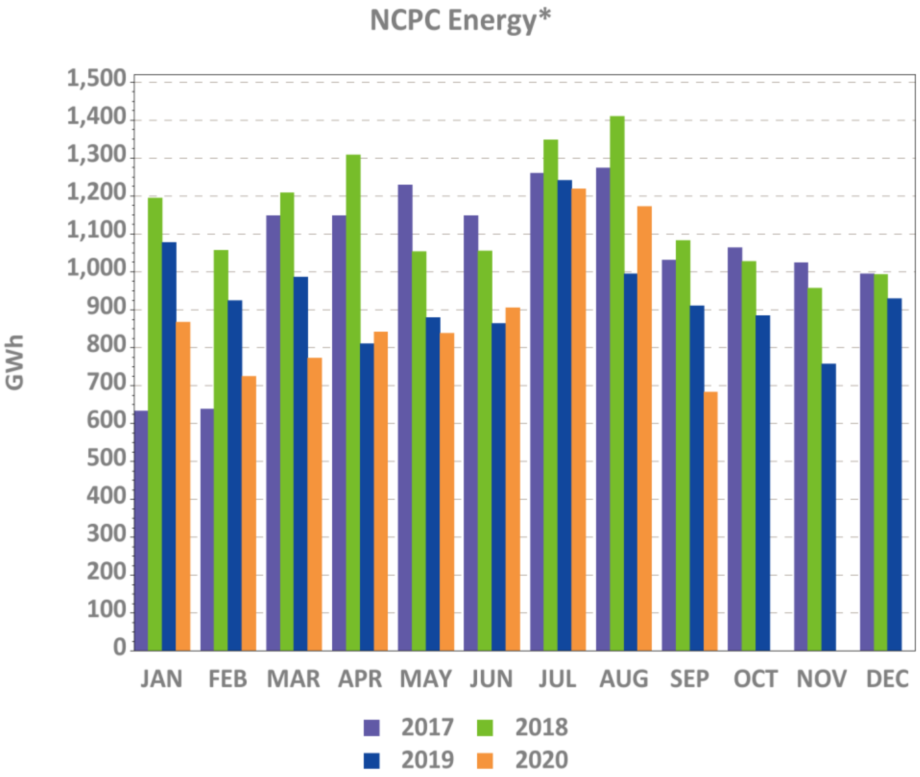
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing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

Charge Allocation Key

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

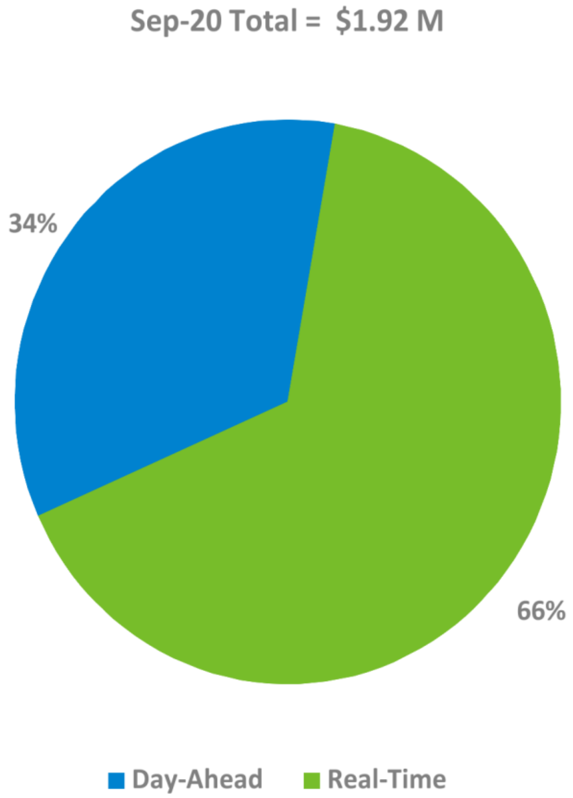
Year-Over-Year Total NCPC Dollars and Energy

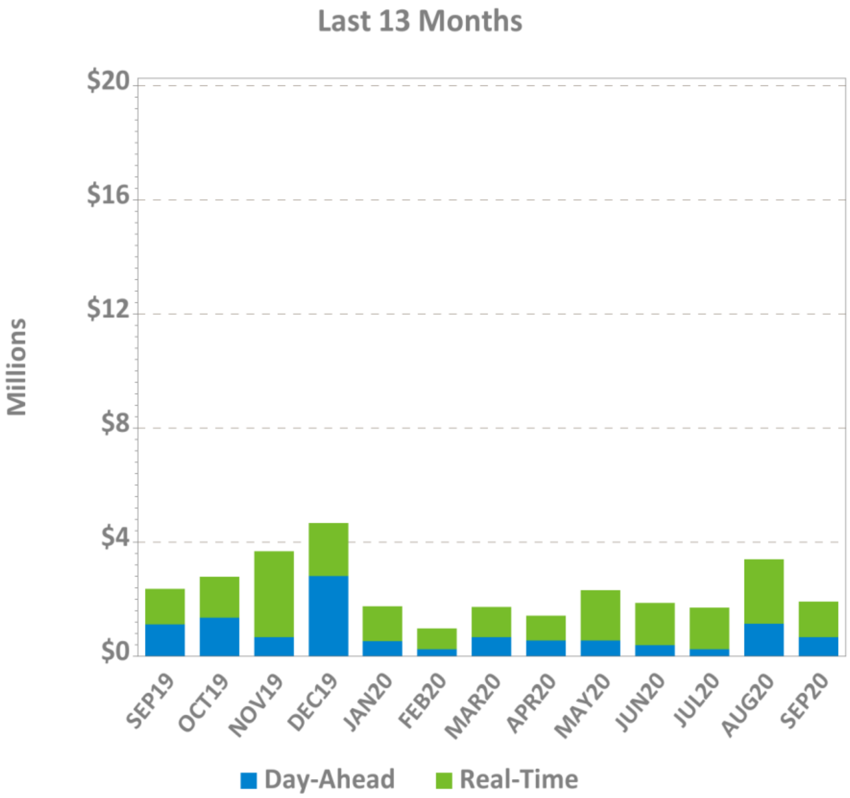




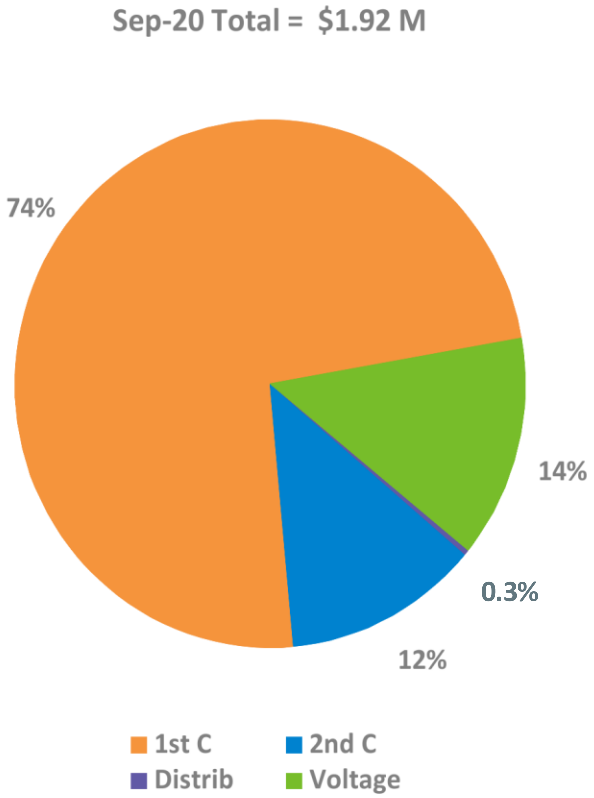
* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

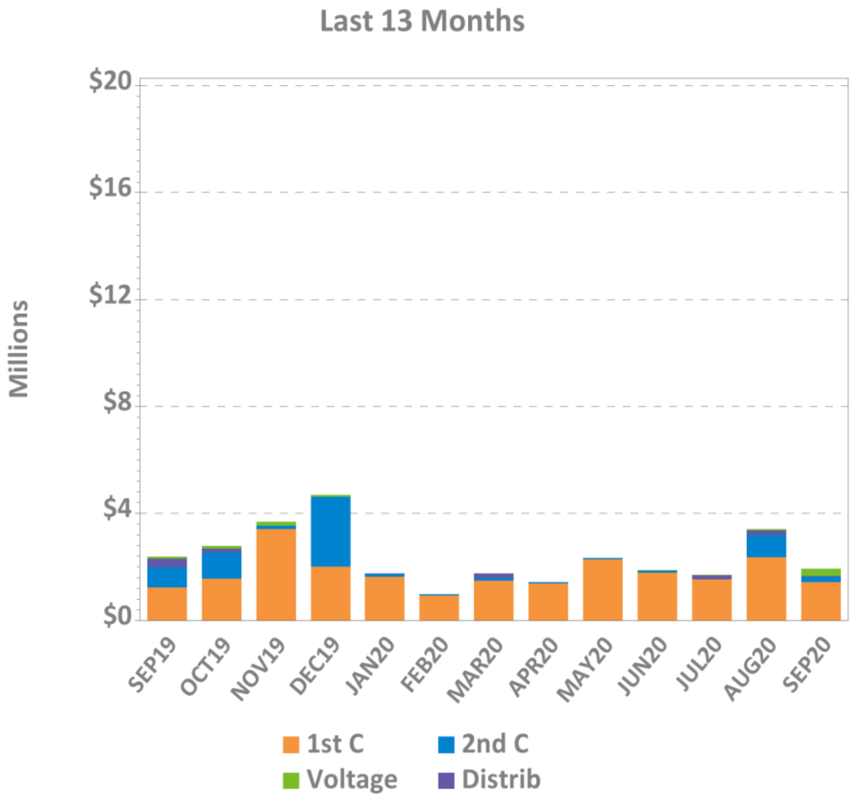
DA and RT NCPC Charges





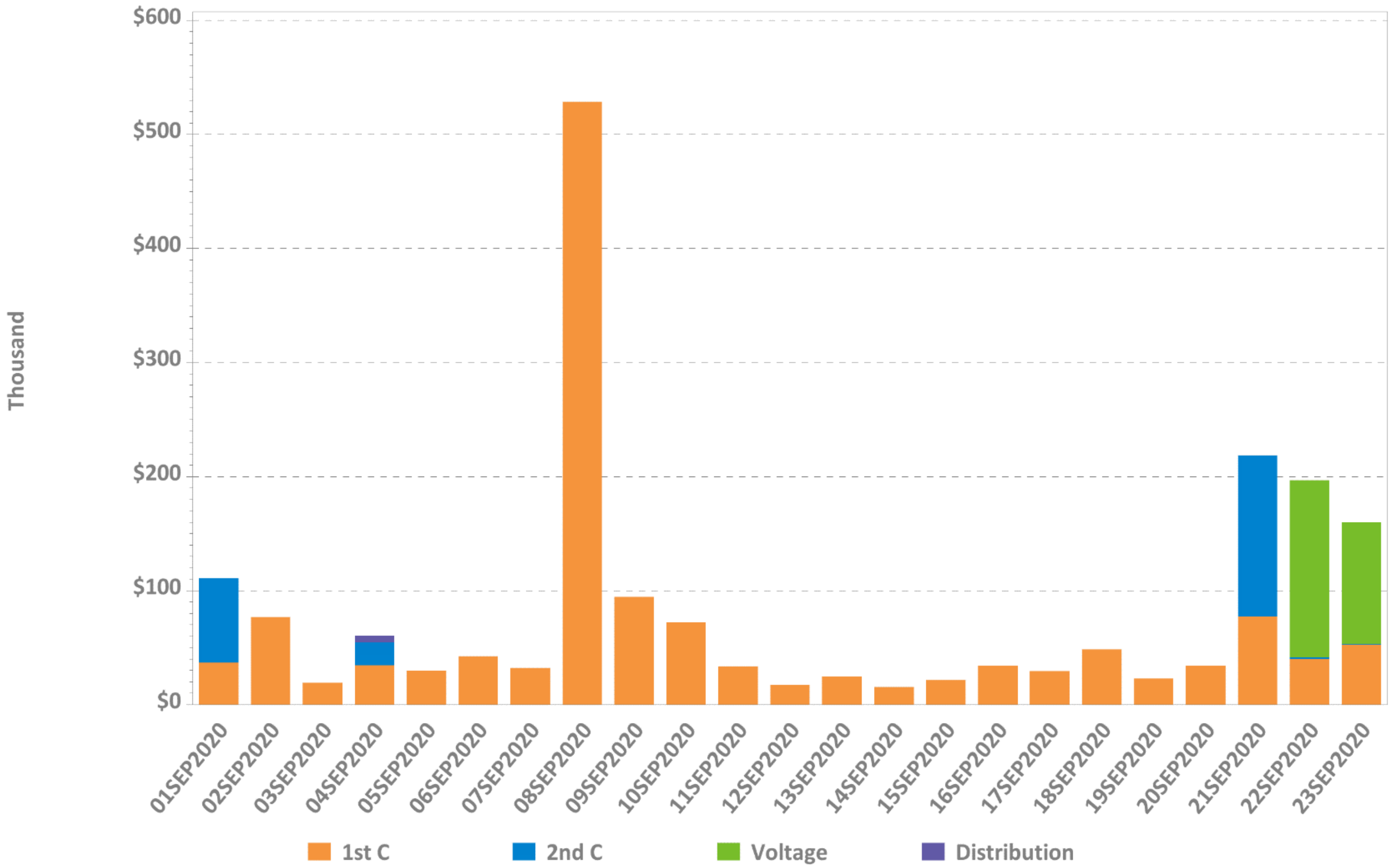
NCPC Charges by Type



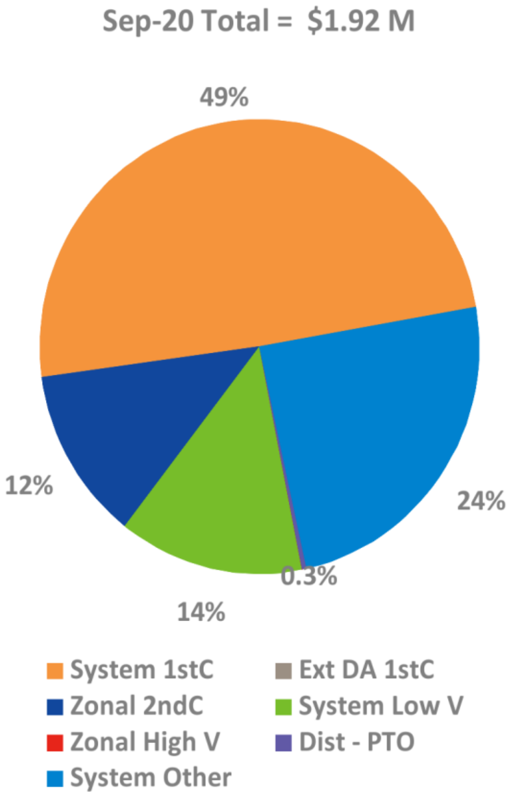


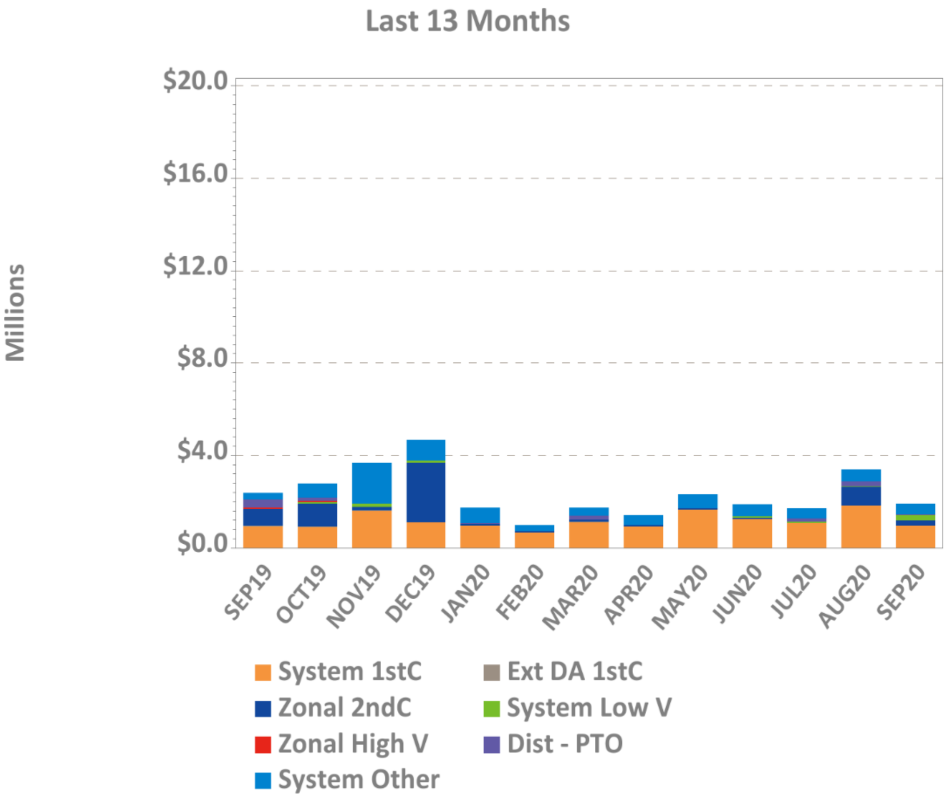
1^{st} C – First Contingency
2^{nd} C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



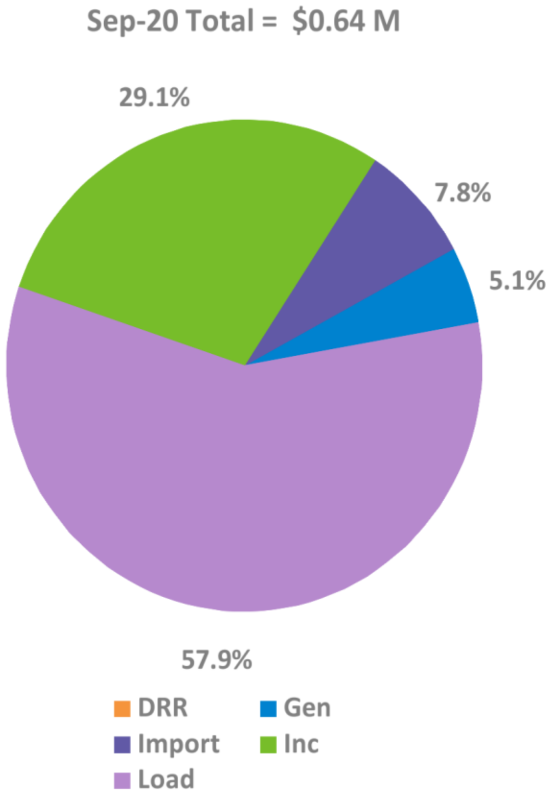
NCPC Charges by Allocation

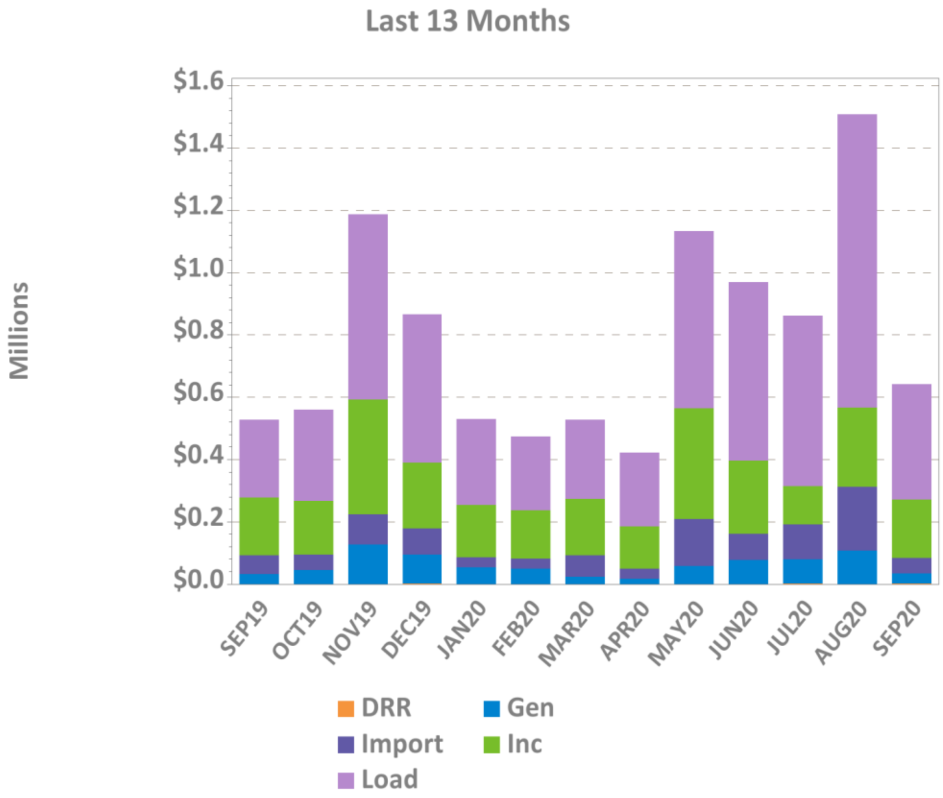




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

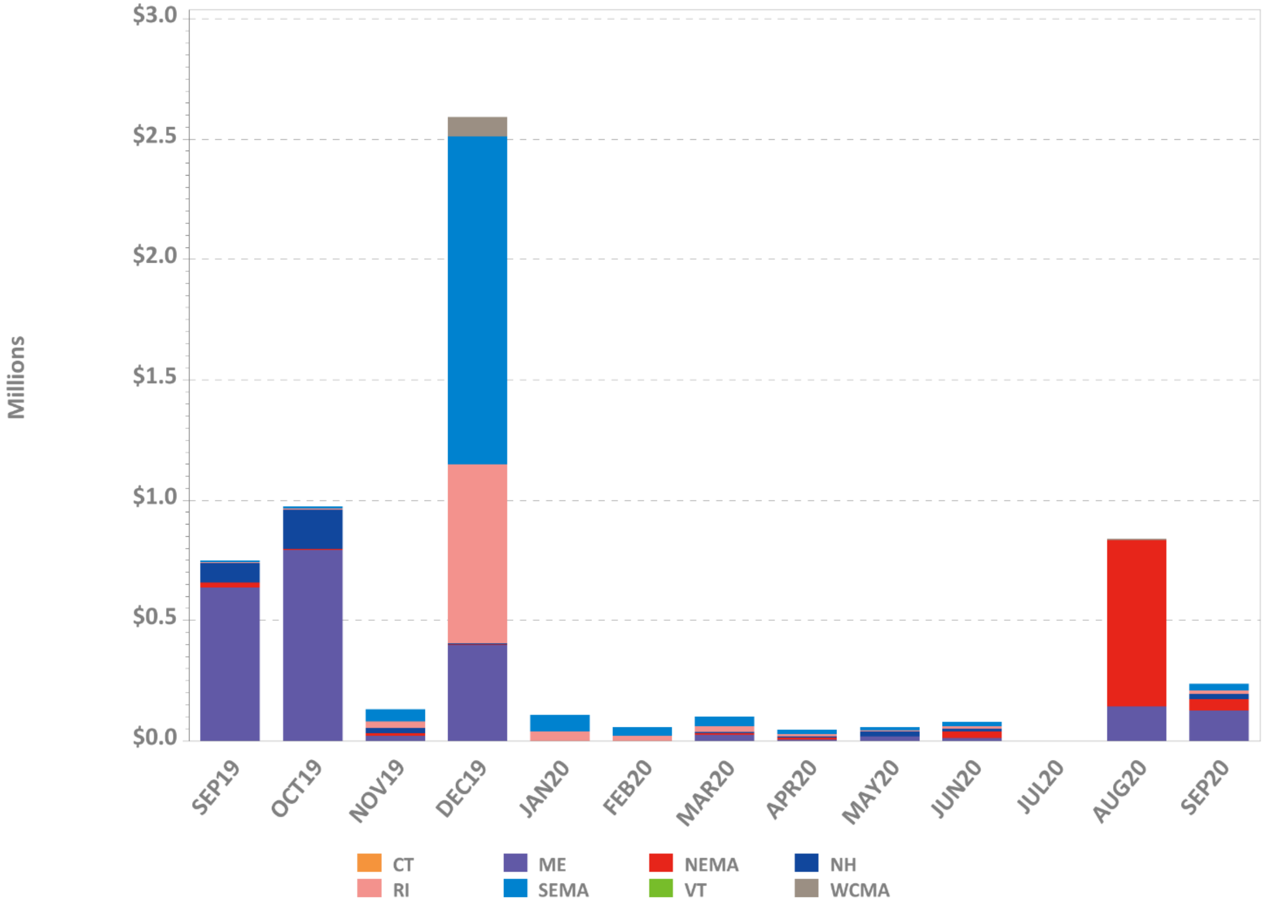
RT First Contingency Charges by Deviation Type





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

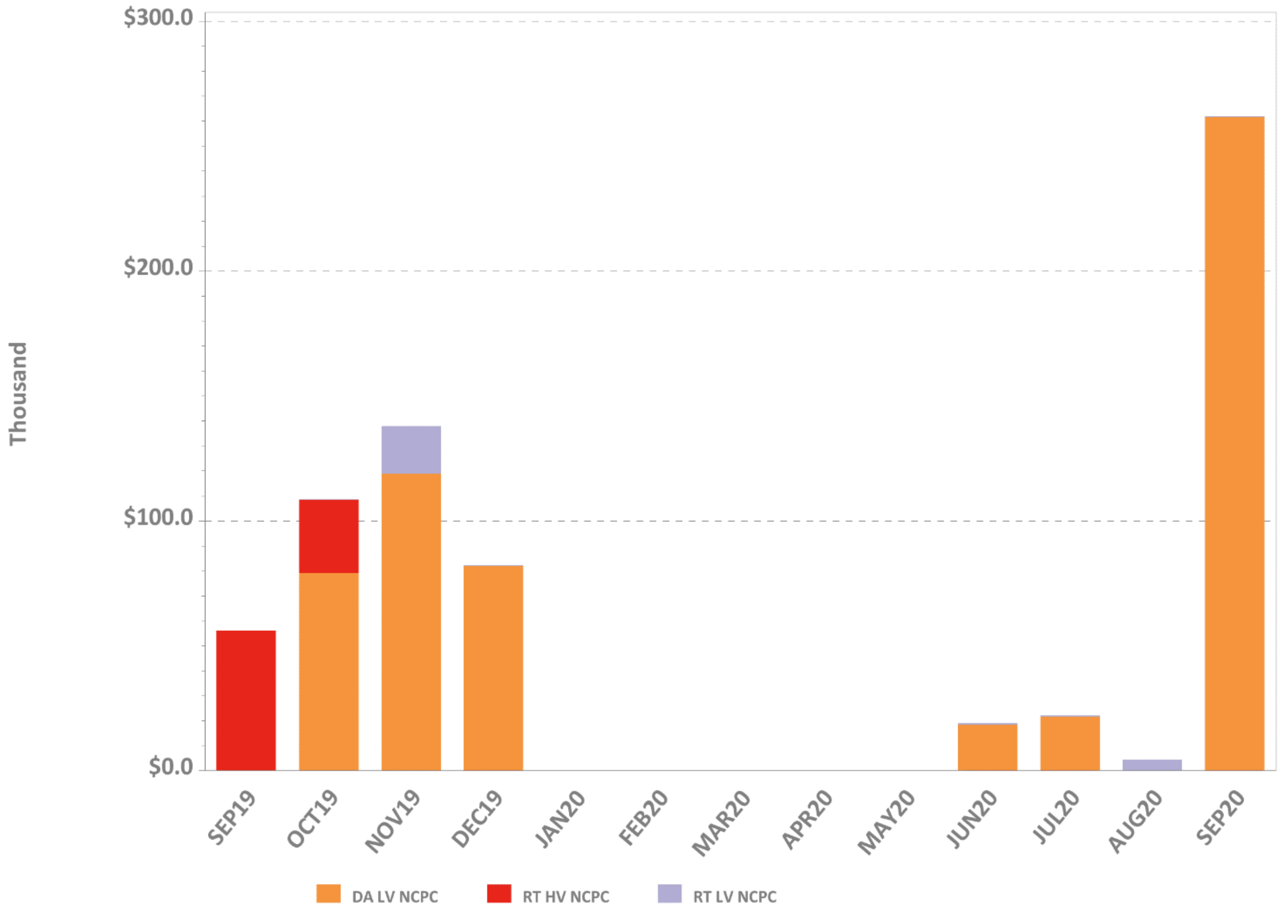
LSCPR Charges by Reliability Region



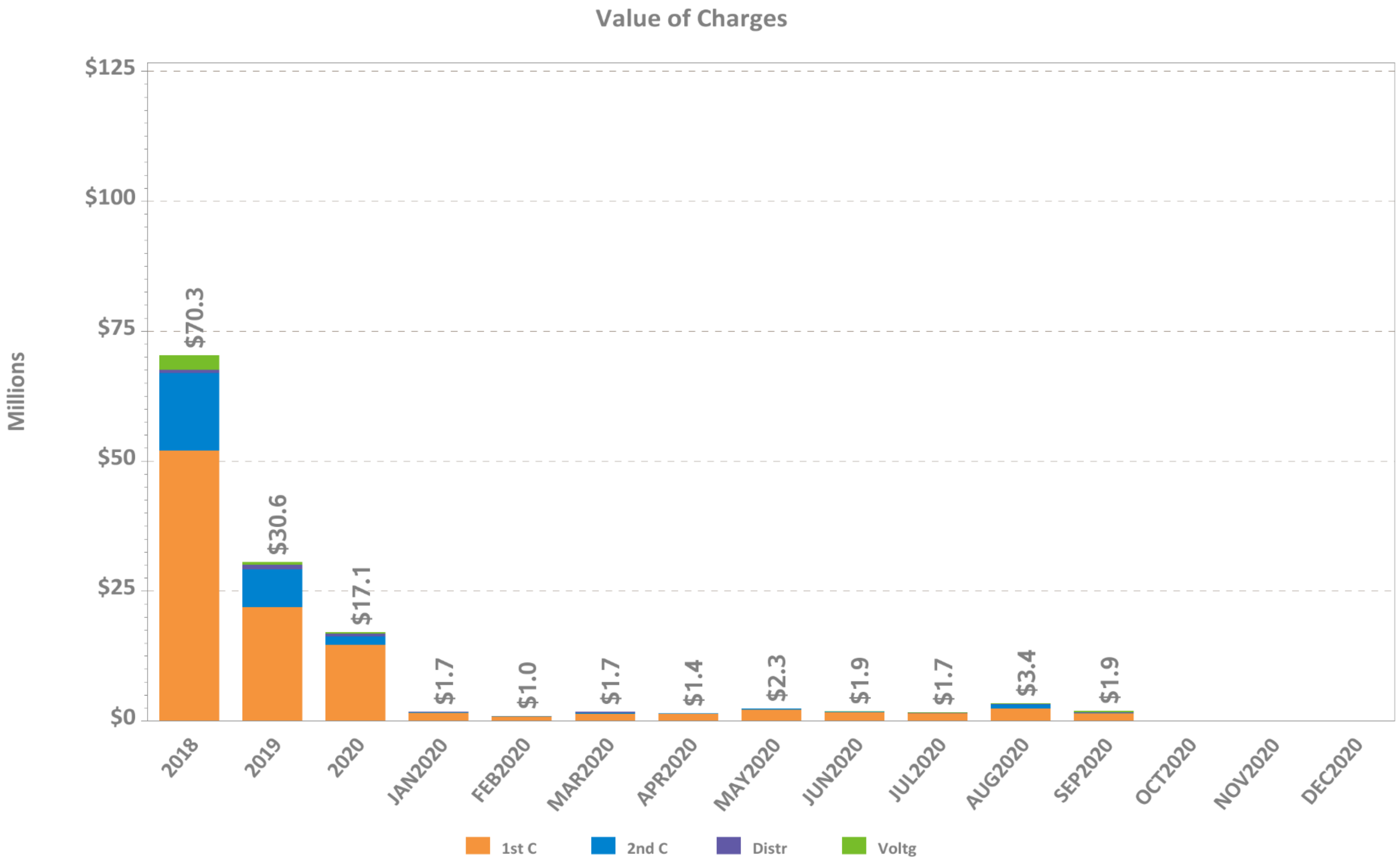
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

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

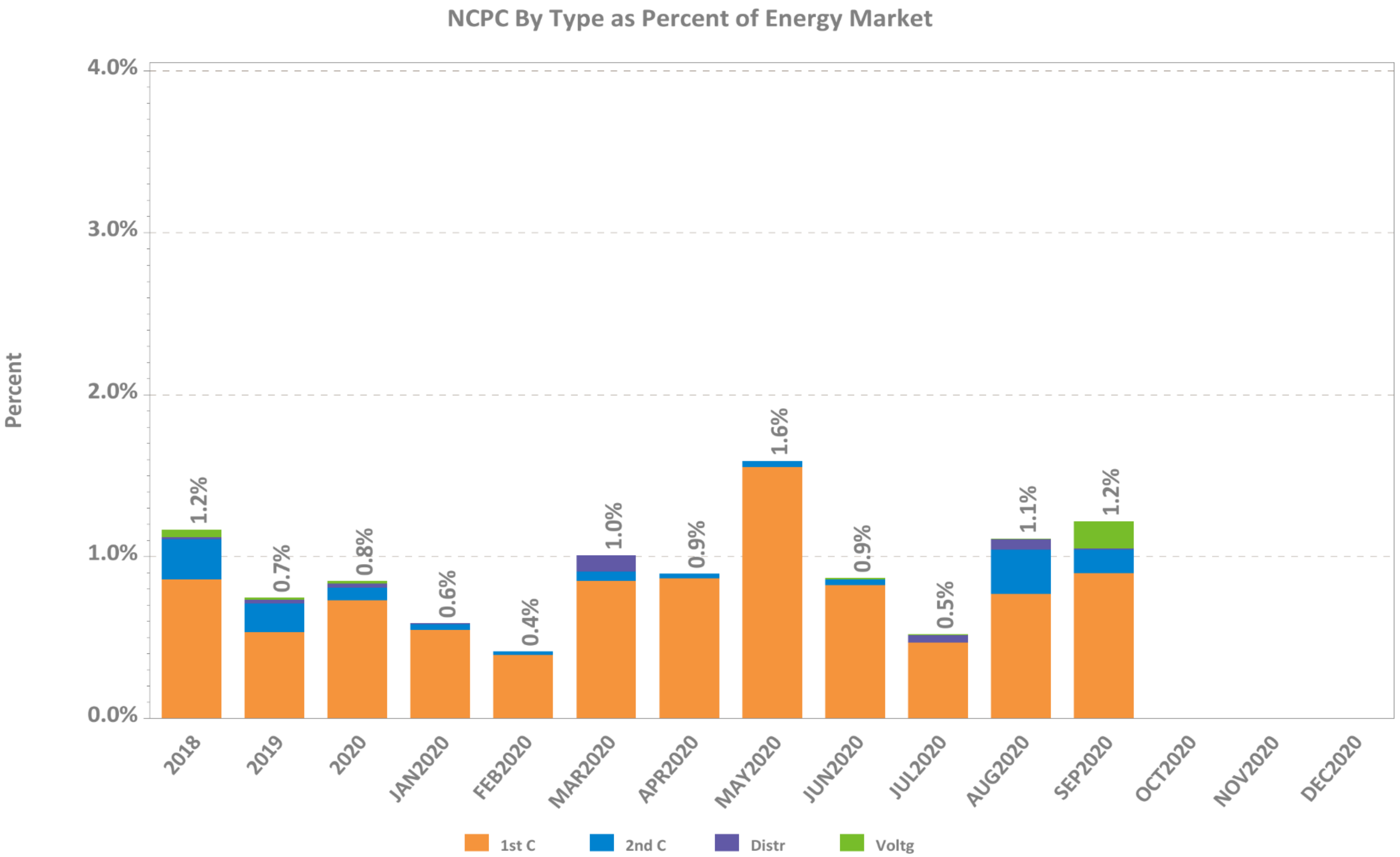
NCPC Charges for Voltage Support and High Voltage Control



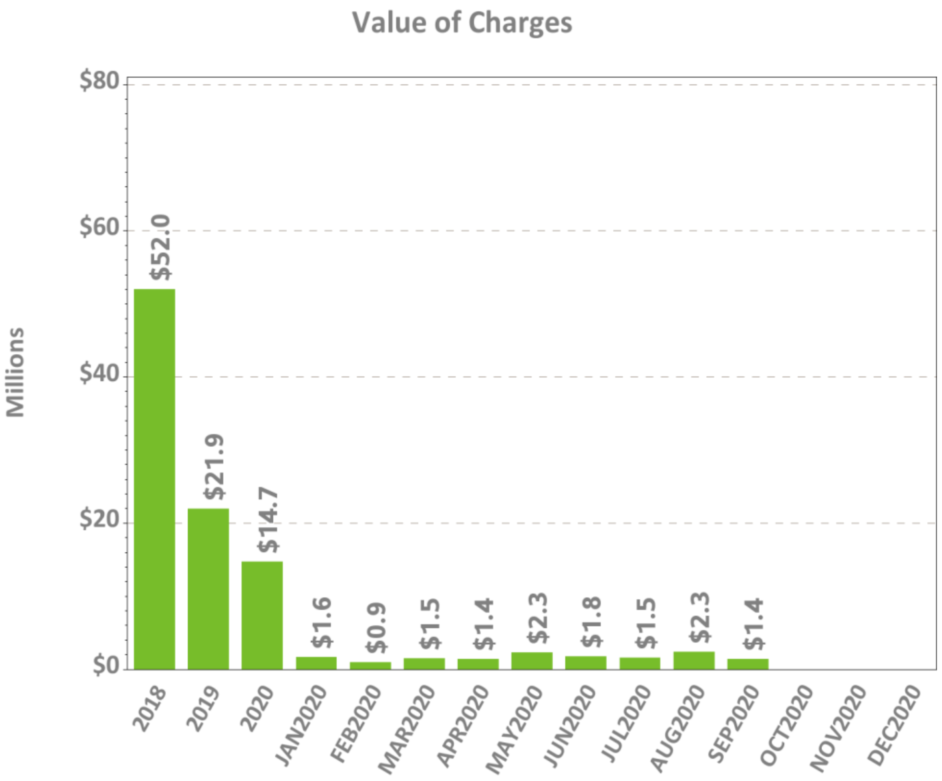
NCPC Charges by Type

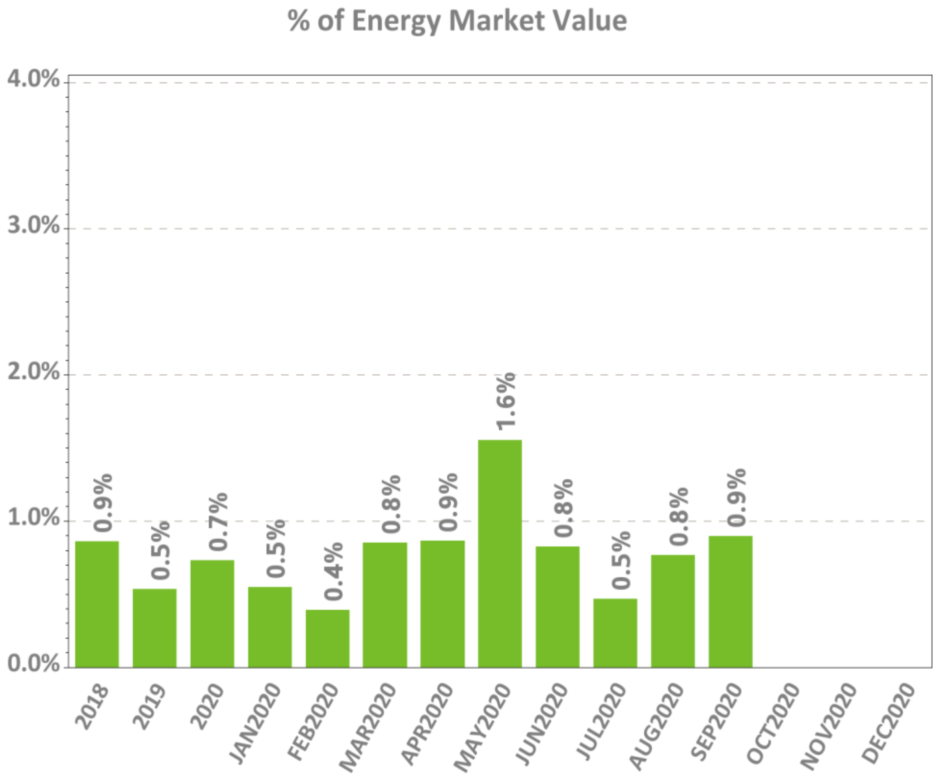


NCPC Charges as Percent of Energy Market



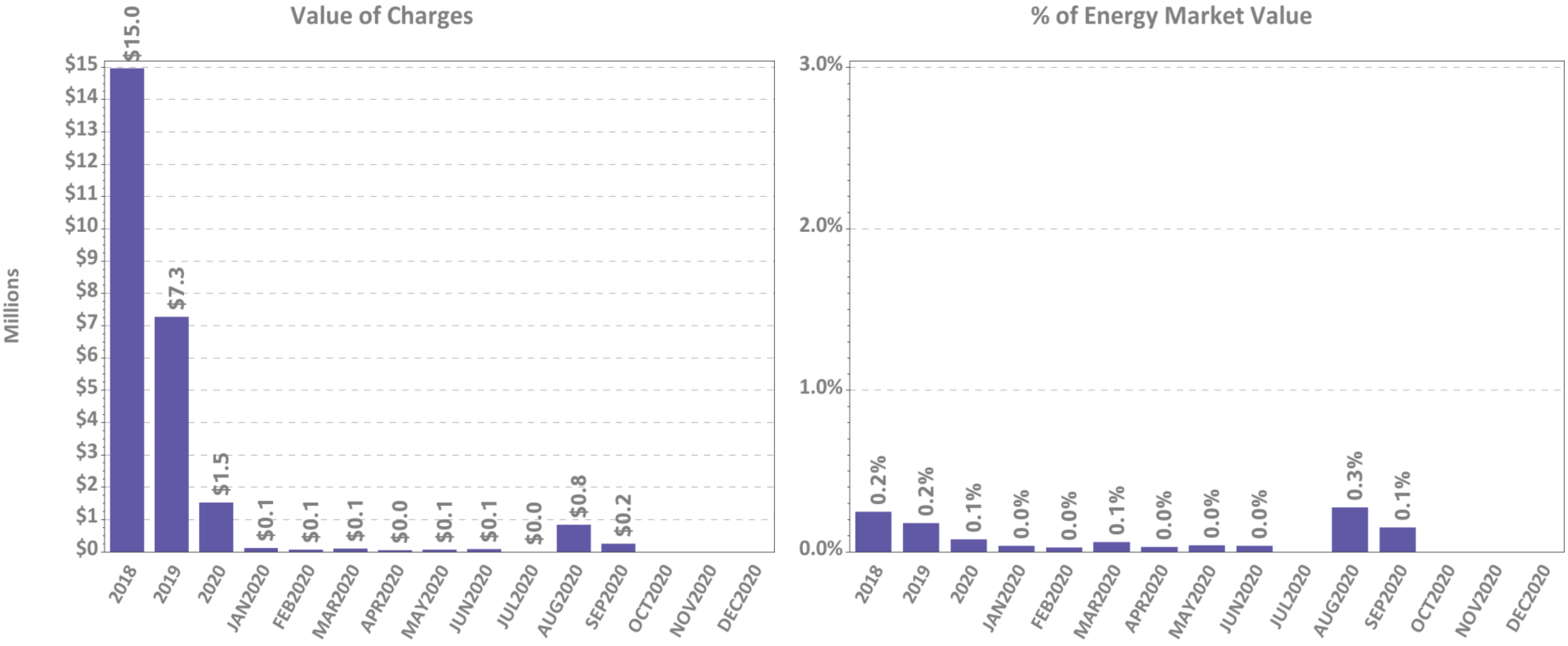
First Contingency NCPC Charges





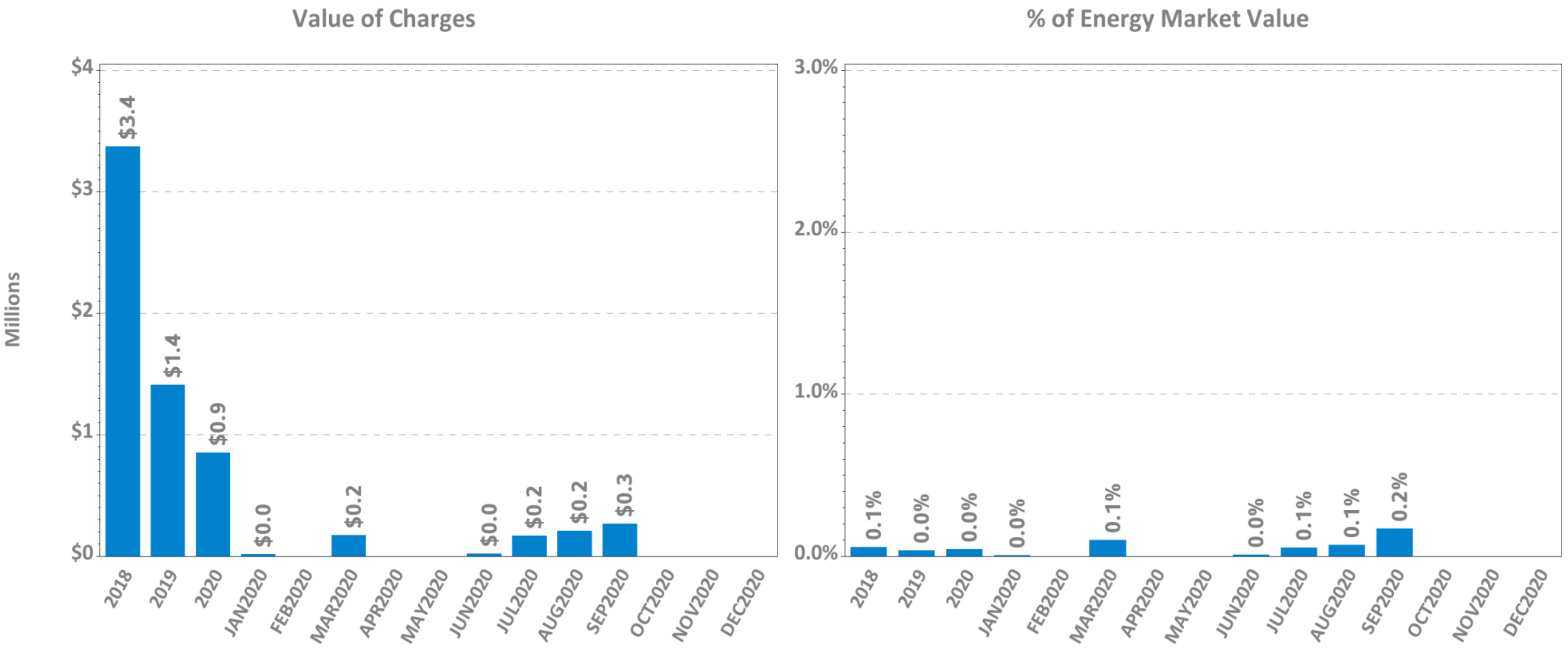
Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

Second Contingency NCPC Charges



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

Voltage and Distribution NCPC Charges



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

DA vs. RT Pricing

The following slides outline:

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

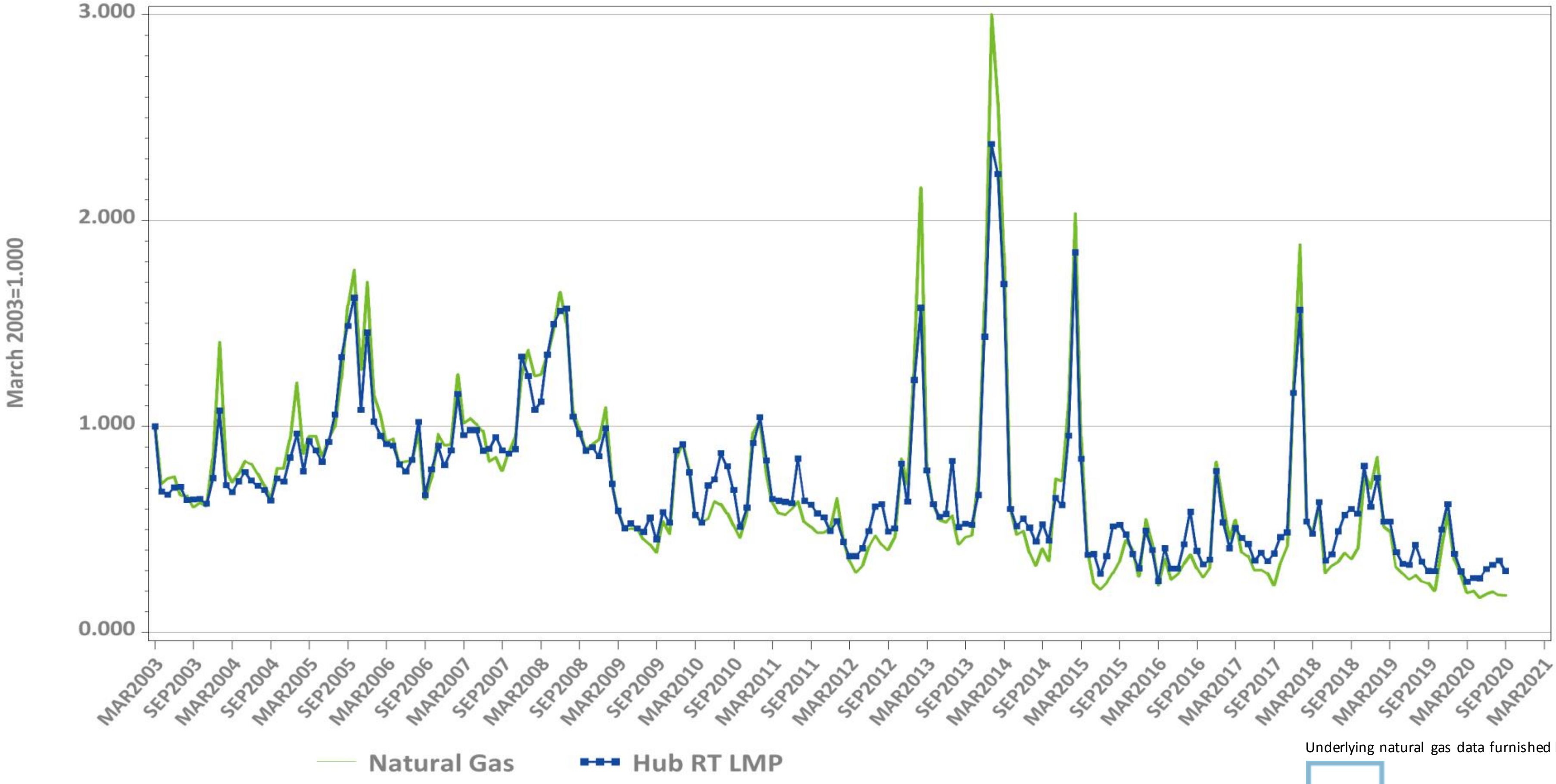
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 2018	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$44.45	$43.60	$42.63	$44.04	$43.71	$44.11	$44.62	$44.19	$44.13
Real-Time	$43.87	$43.13	$41.03	$43.17	$42.83	$43.37	$43.68	$43.58	$43.54
RT Delta %	-1.3%	-1.1%	-3.8%	-2.0%	-2.0%	-1.7%	-2.1%	-1.4%	-1.3%
Year 2019	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Day-Ahead	$31.54	$30.72	$30.76	$31.20	$30.67	$31.19	$31.51	$31.24	$31.22
Real-Time	$30.92	$30.26	$30.12	$30.70	$30.05	$30.61	$30.80	$30.68	$30.67
RT Delta %	-2.0%	-1.5%	-2.1%	-1.6%	-2.0%	-1.9%	-2.2%	-1.8%	-1.8%

September-19	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$21.35	$20.75	$20.97	$21.29	$20.94	$21.07	$21.35	$21.15	$21.14
Real-Time	$20.67	$20.21	$20.27	$20.59	$20.26	$20.37	$20.60	$20.45	$20.45
RT Delta %	-3.2%	-2.6%	-3.3%	-3.3%	-3.2%	-3.3%	-3.5%	-3.3%	-3.3%
September-20	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Day-Ahead	$20.73	$19.69	$20.79	$20.75	$20.08	$20.17	$20.51	$20.41	$20.41
Real-Time	$20.78	$19.98	$21.30	$20.86	$20.25	$20.23	$20.53	$20.47	$20.47
RT Delta %	0.2%	1.5%	2.5%	0.5%	0.9%	0.3%	0.1%	0.3%	0.3%
Annual Diff.	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Yr over Yr DA	-2.9%	-5.1%	-0.9%	-2.5%	-4.1%	-4.2%	-3.9%	-3.5%	-3.5%
Yr over Yr RT	0.5%	-1.1%	5.1%	1.3%	0.0%	-0.7%	-0.3%	0.1%	0.1%

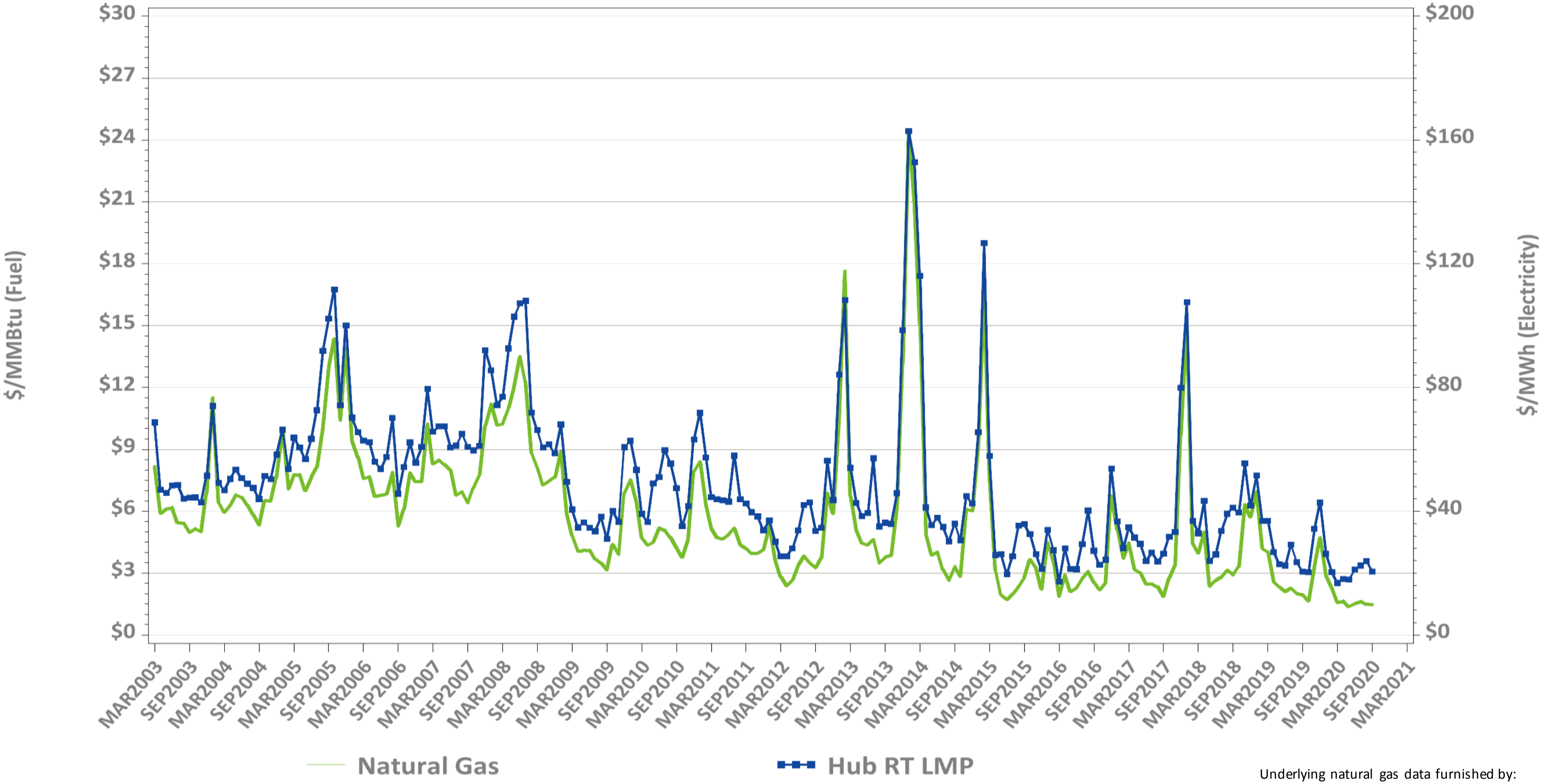
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

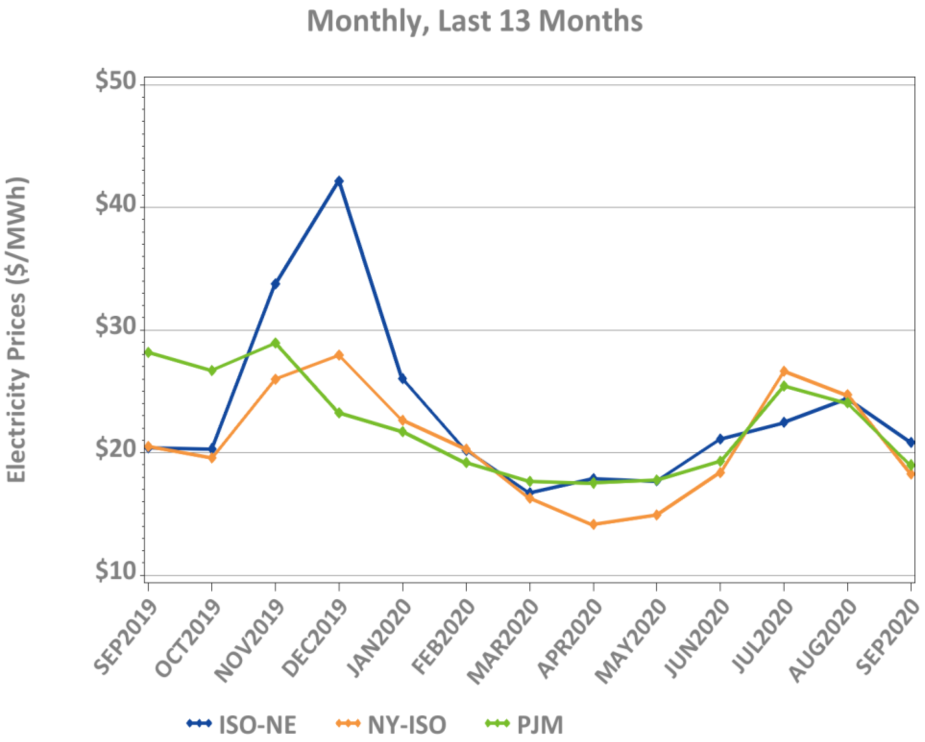
ice Global markets in clear view

Monthly Average Fuel Price and RT Hub LMP

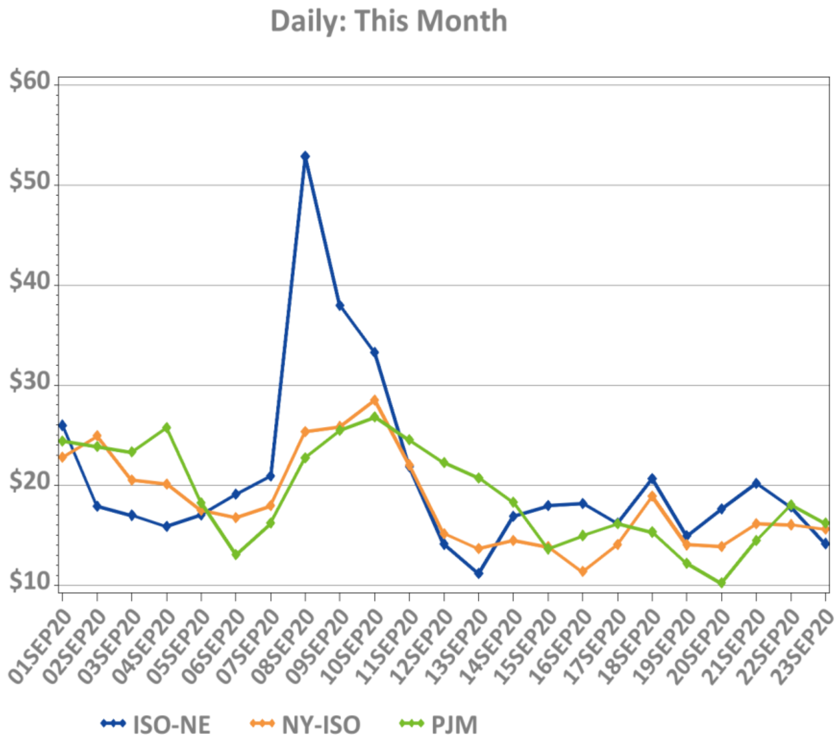


Underlying natural gas data furnished by: ICE Global markets in clear view

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

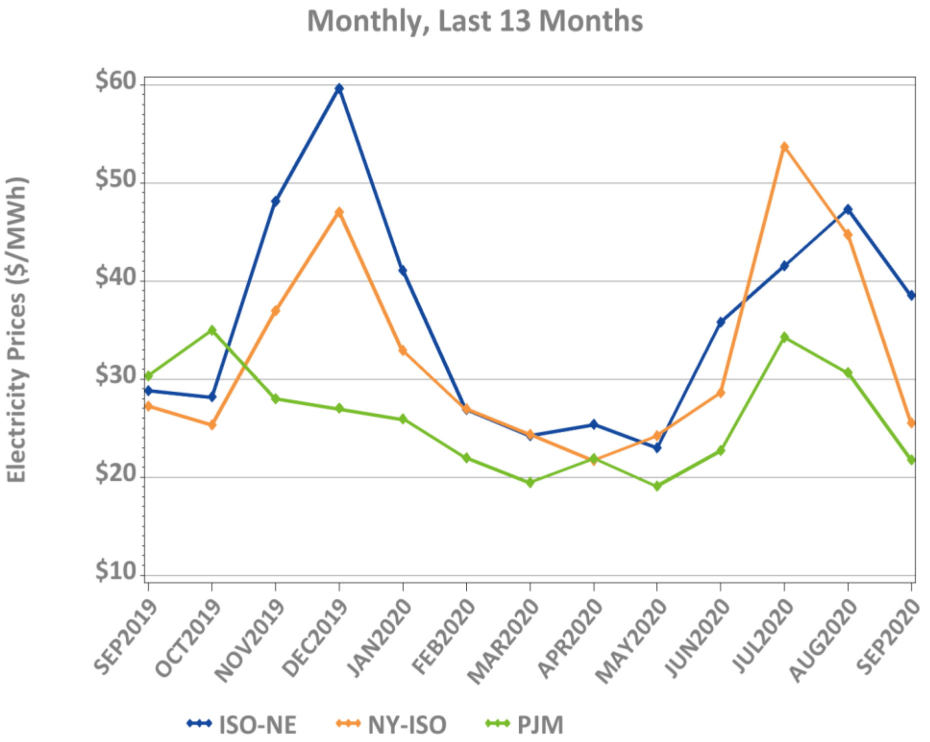

Monthly, Last 13 Months

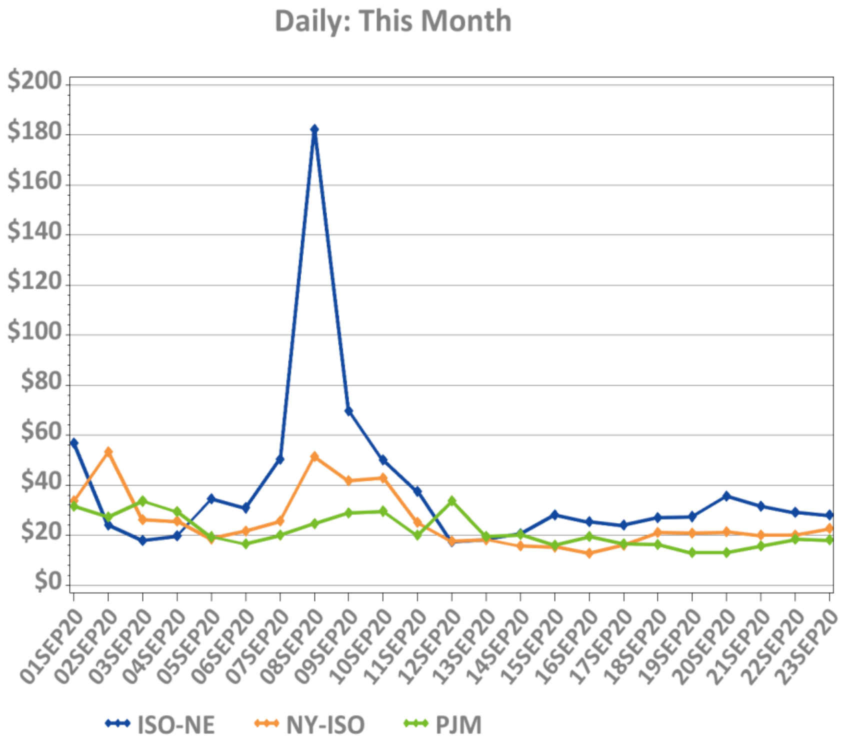
*Note: Hourly average prices are shown.


Daily: This Month

*Note: Hourly average prices are shown.

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


Monthly, Last 13 Months


Daily: This Month

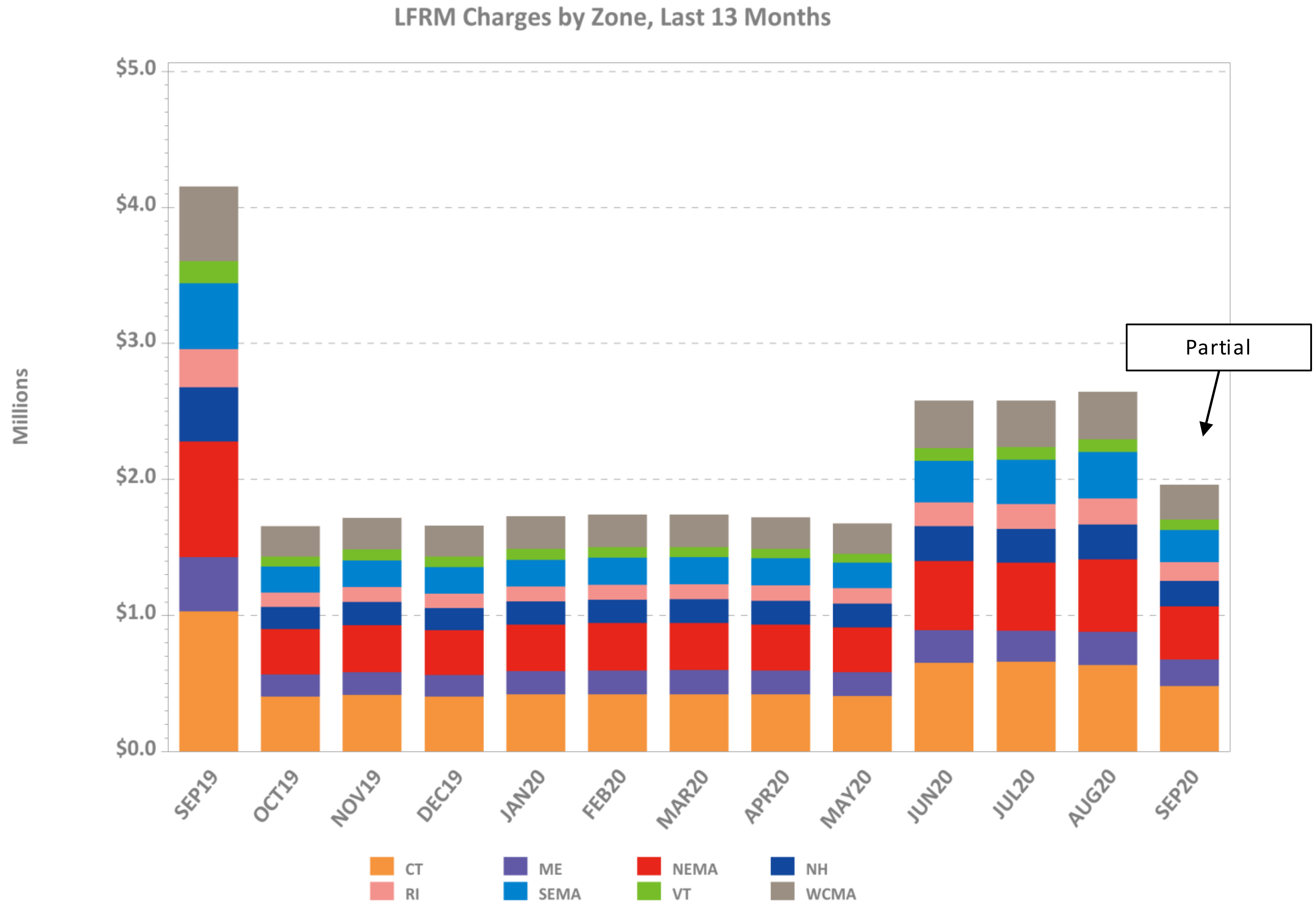
***Forecasted New England daily peak hours reflected**

Reserve Market Results – September 2020

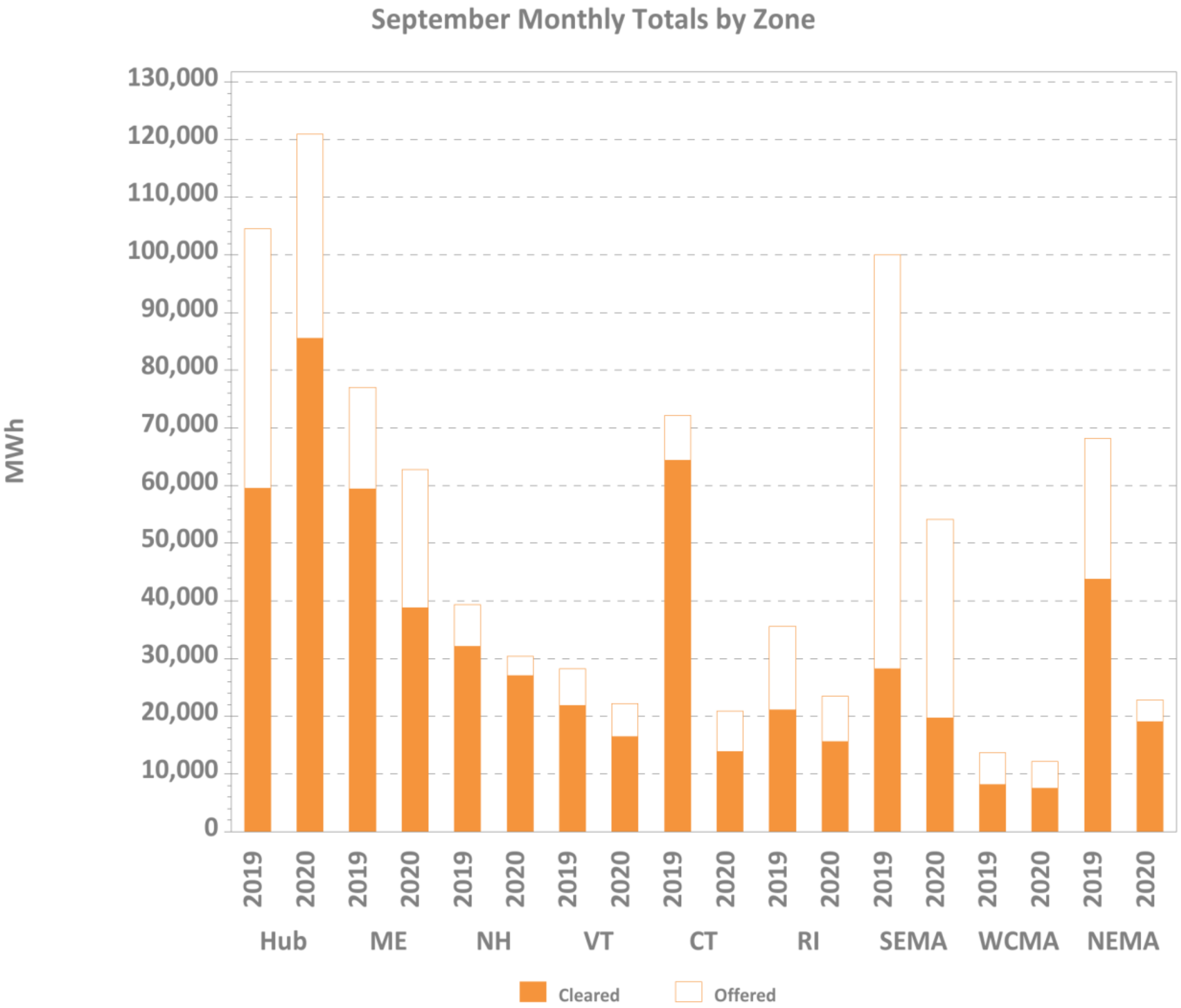
- Maximum potential Forward Reserve Market payments of $2.1M were reduced by credit reductions of $39K, failure-to-reserve penalties of $61K and failure-to-activate penalties of $4K, resulting in a net payout of $2M or 95% of maximum
  - Rest of System: $1.55M/1.65M (94%)
  - Southwest Connecticut: $0.06M/0.06M (99%)
  - Connecticut: $0.35M/0.36M (98%)
- $942K total Real-Time credits were reduced by $276K in Forward Reserve Energy Obligation Charges for a net of $666K in Real-Time Reserve payments
  - Rest of System: 200 hours, $402K
  - Southwest Connecticut: 200 hours, $150K
  - Connecticut: 200 hours, $74K
  - NEMA: 200 hours, $41K

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

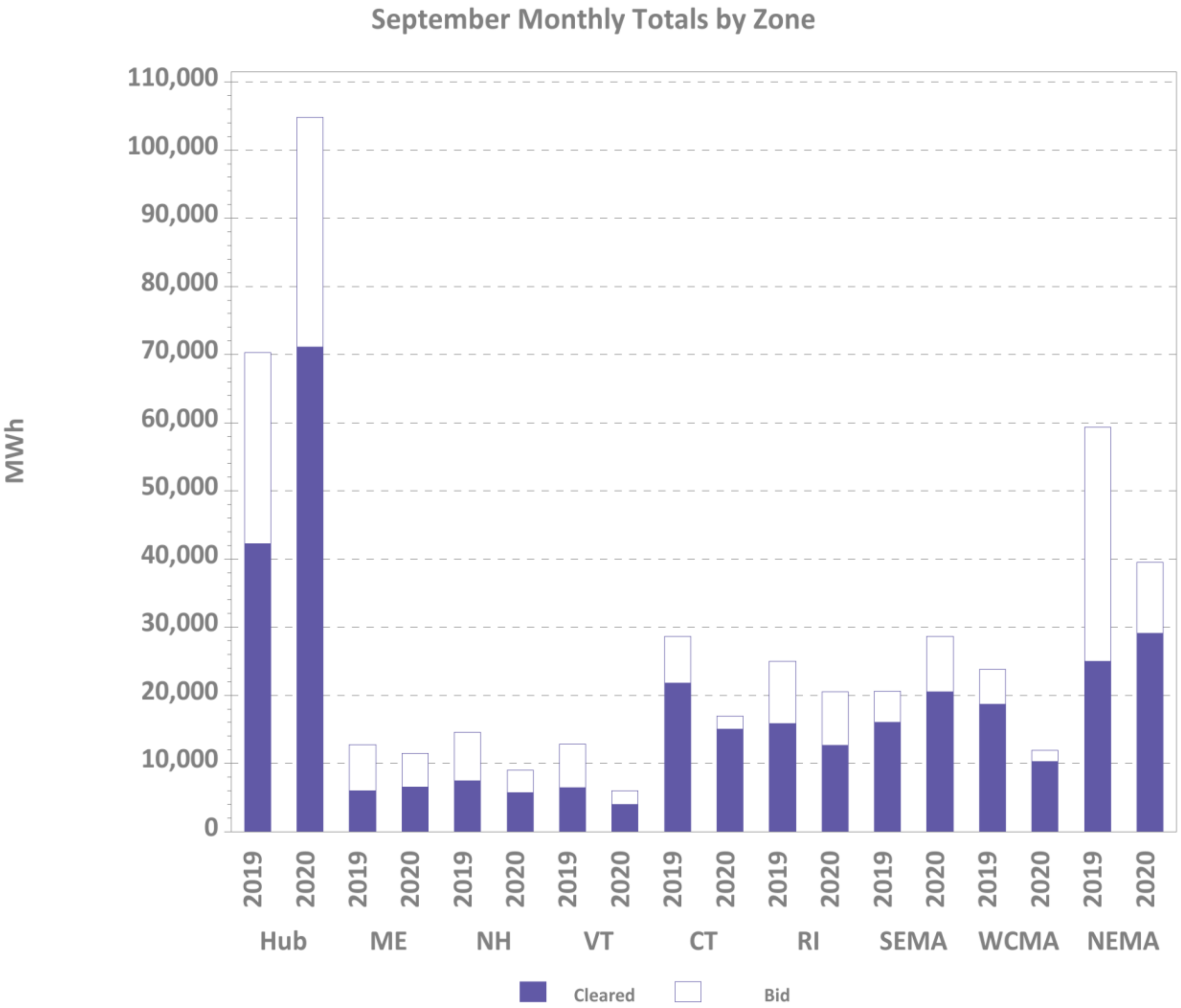
LFRM Charges to Load by Load Zone ($)



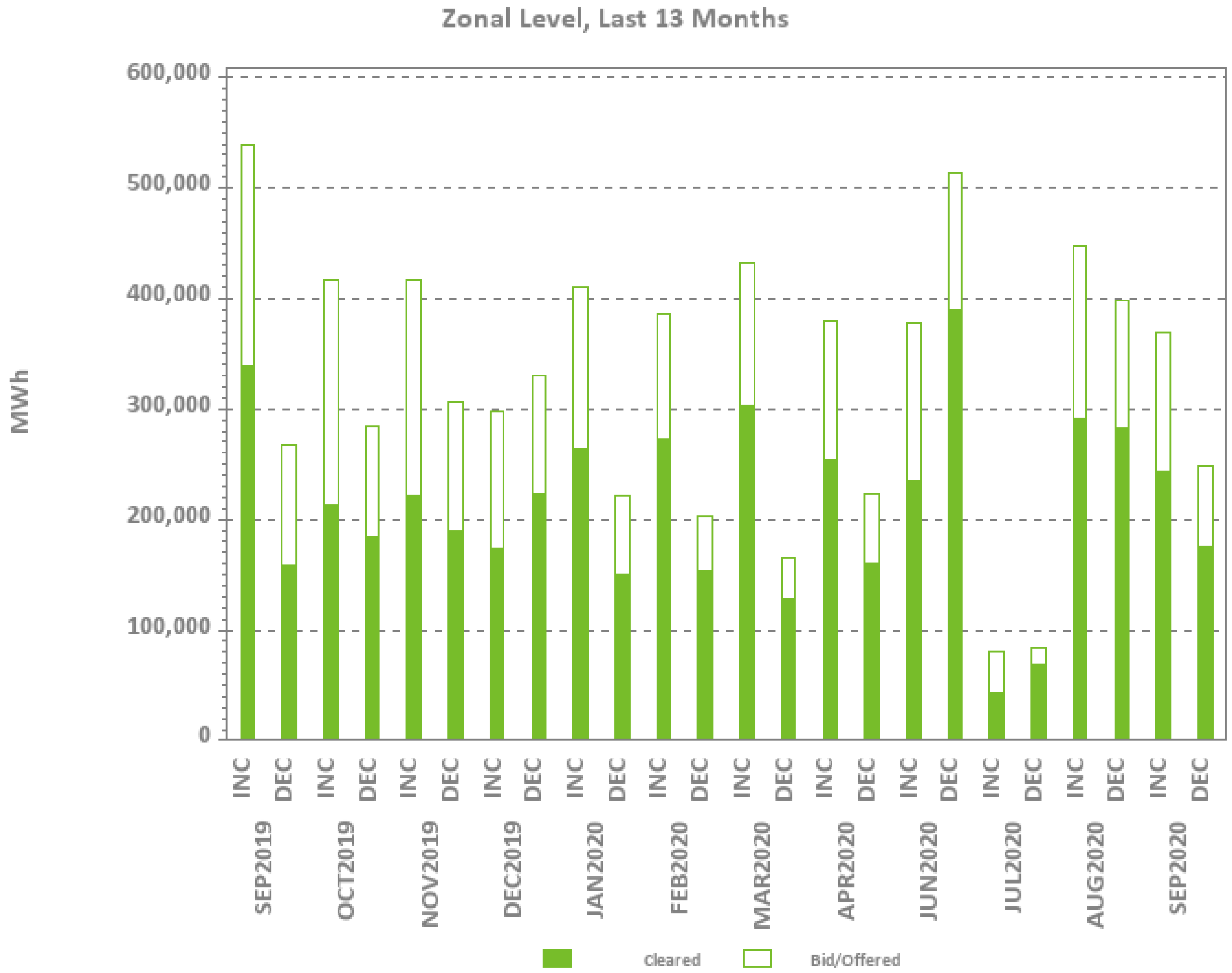
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

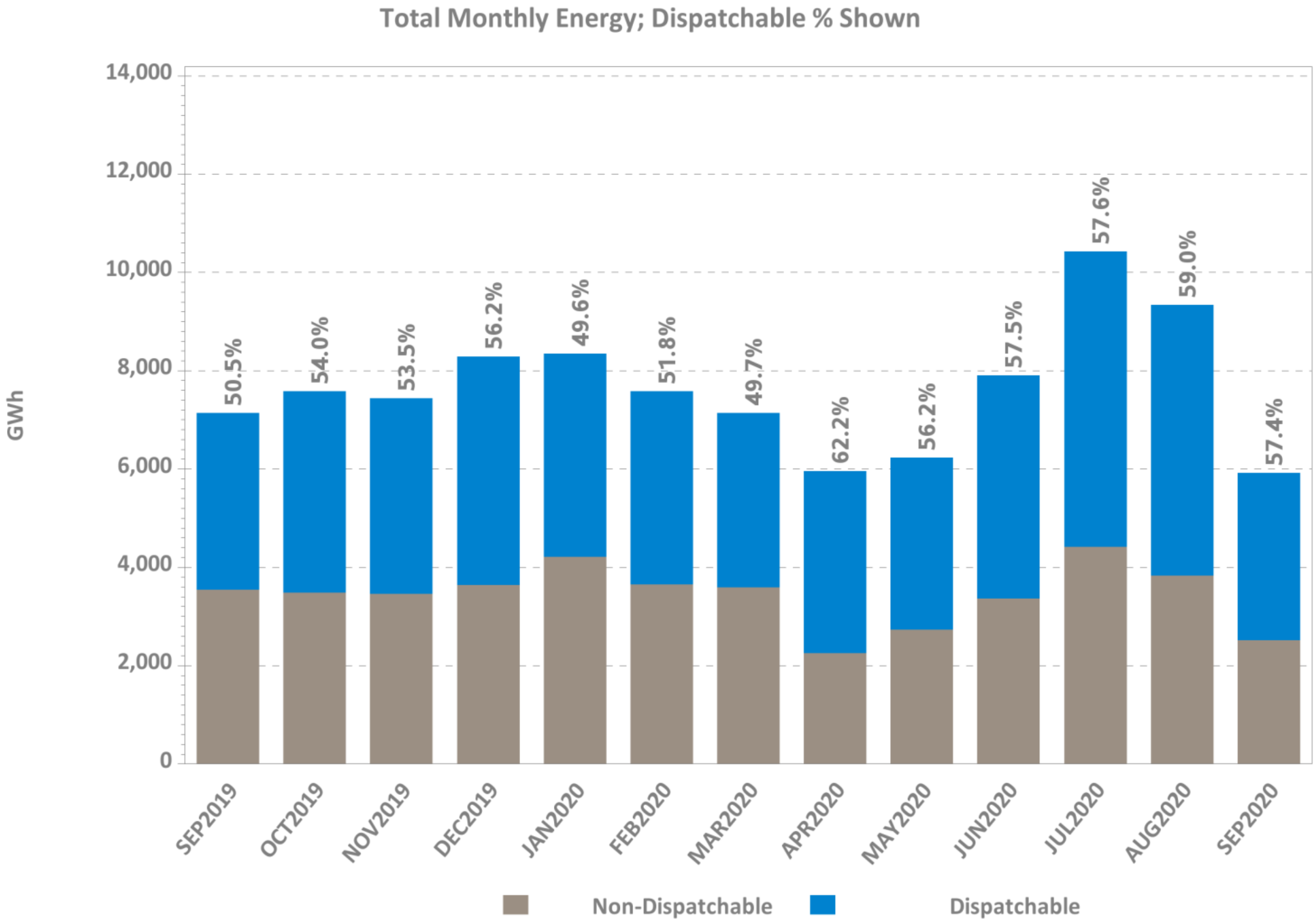


Total Increment Offers and Decrement Bids



Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation



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

REGIONAL SYSTEM PLAN (RSP)

Planning Advisory Committee (PAC)

- October 21 PAC Meeting Agenda Topics*
  - RSP Transmission Projects and Asset Condition - October 2020 Update
  - Transmission Owners’ Local System Plan Presentations

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

Transmission Planning for the Clean-Energy Transition

- On September 24, the ISO initiated discussions with the PAC about proposed refinements to study assumptions that better reflect long-term trends, such as increased amounts of distributed-energy resources (primarily solar PV), offshore wind generation, and battery energy storage
- Initial topics being discussed include:
  - New study conditions based on time of day/time of year
  - Load level assumptions
  - Onshore and offshore wind output assumptions
  - Photovoltaic output assumptions
  - The need for more detailed distributed energy resource information

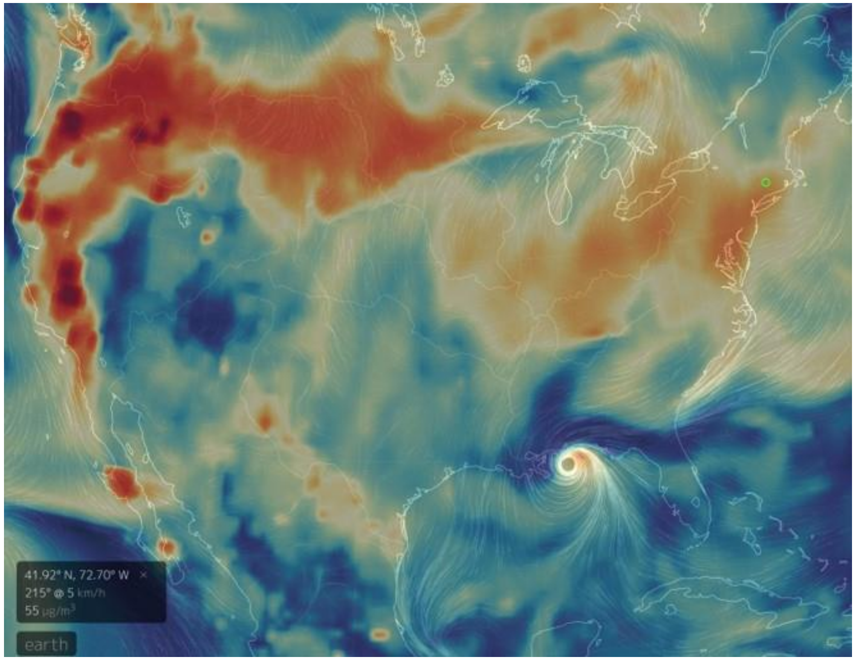
Economic Studies

- Three 2019 study requests were received (NESCOE, Anbaric, and RENEW)
  - Study work is complete and results have been presented to PAC
    - NESCOE report was posted to the ISO website on June 30
    - Anbaric report expected to be published by October 1
    - RENEW report expected to be published in late October
- NGRID submitted a 2020 economic study request
  - Assumptions have been agreed upon and were presented to PAC in May, June and July
  - Preliminary production cost results are anticipated to be shared at the November PAC, and the goal is to complete all study work by Q1 2021
- ISO-NE website enhancement project is ongoing
  - All reports are now accessible from a single point on the website
  - Additional modifications related to study metrics are expected in Q4

Environmental Issues

- Preliminary monitoring data indicates a moderate ground level ozone smog season across New England over the summer
- Smoke from West Coast wildfires reached New England and contributed to regional haze and a decline in solar production in the region
- Next Environmental Advisory Group (EAG) meeting is scheduled for October 6
- Various updates are being made to the EAG web page and quarterly reports are being introduced to improve user access to relevant environmental performance data and regulatory developments

Wildfire Smoke Crossing U.S. Mid-September 2020



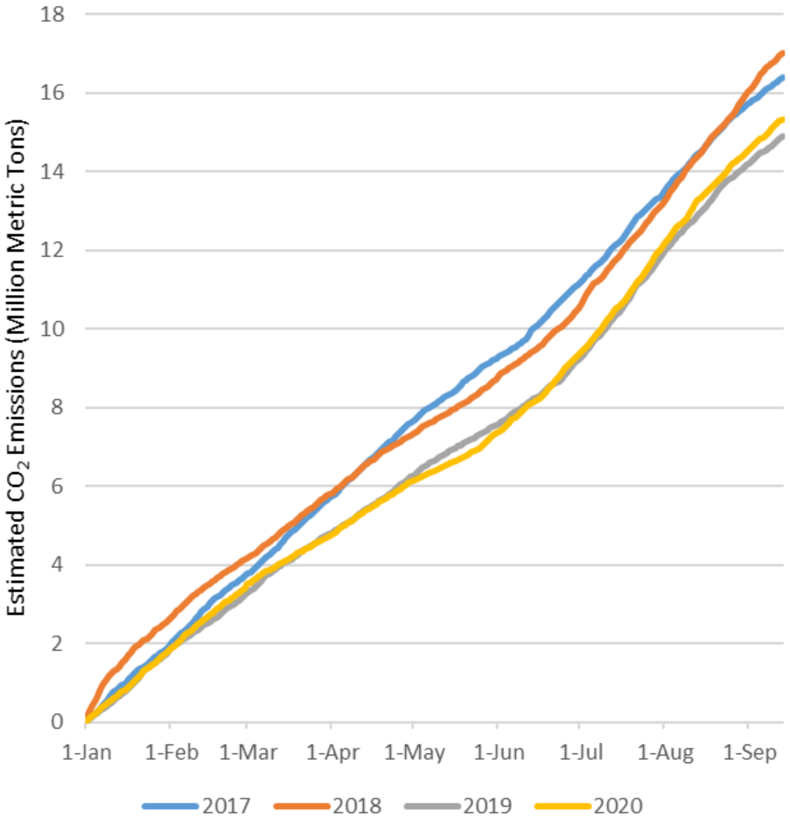
Wind and particle matter pollution (blue to dark red) estimated surface concentrations from various satellite measurements on 9/16/2020

Environmental Matters – Carbon Dioxide (CO_2) Emissions from Native Generation (1/1 - 9/14)

Estimated Emissions Increasing 2020 vs. 2019

- Estimated 2020 YTD CO_2 system emissions increased 3% compared to same period in 2019 (1/1 - 9/16):
  - Coal -81%
  - Oil -8.5%
  - Natural Gas 5.5%
- 2020 YTD (40,071 GWh) native emitting generation exceeded 2019 YTD (38,622 GWh) by 3.8%
  - Increases in natural gas generation (4.8%) and net imports (2.5%), offset decline in nuclear generation (-15.8%)

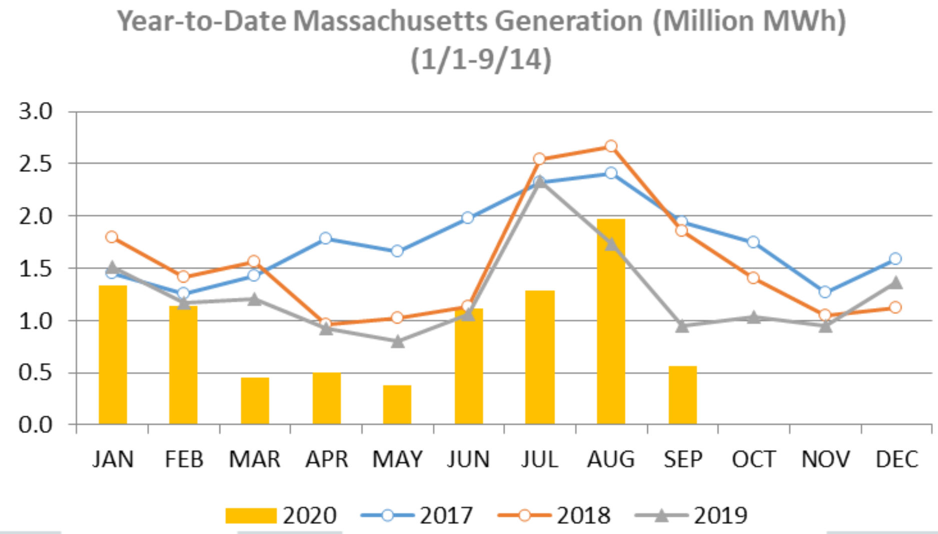
Cumulative CO_2 System Emissions (Million Metric Tons)



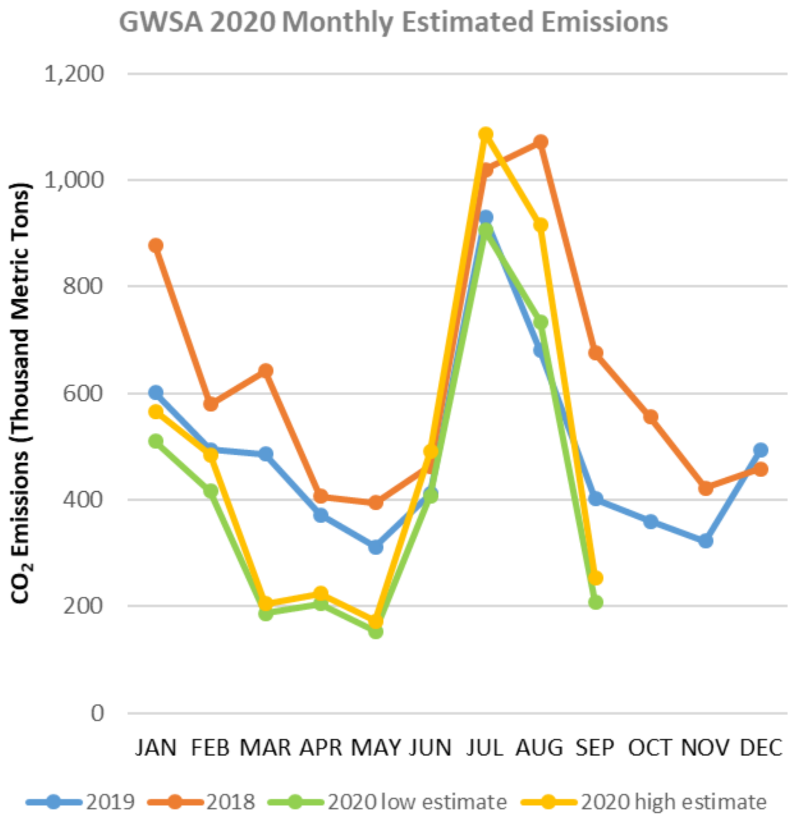
Environmental Matters – Massachusetts CO_2 Generator Emissions Cap

2020 CO_2 Estimated Emissions Remain Lower Than 2019

- YTD CO_2 emissions estimated between 80% - 94% of same period in 2019
- YTD generation 25% compared to same period in 2019



2020 Estimated Past Monthly Emissions (Thousand Metric tons)



GWSA - Global Warming Solutions Act

RSP Project Stage Descriptions

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

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

Greater Hartford and Central Connecticut (GHCC) Projects*

Status as of 9/21/20

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

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

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 9/21/20

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

Upgrade	Expected/ Actual In-Service	Present Stage
Terminal equipment upgrades on the 115 kV line from Middletown to Dooley (1050)	Jun-15	4
Terminal equipment upgrades on the 115 kV line from Middletown to Portland (1443)	Jun-15	4
Add a 3.7 mile 115 kV hybrid overhead/underground line from Newington to Southwest Hartford and associated terminal equipment including a 1.4% series reactor	Nov-20	3
Add a 115 kV 25.2 MVAR capacitor at Westside 115 kV substation	Jun-18	4
Loop the 1779 line between South Meadow and Bloomfield into the Rood Avenue substation and reconfigure the Rood Avenue substation	May-17	4
Reconfigure the Berlin 115 kV substation including two new 115 kV breakers and the relocation of a capacitor bank	Nov-17	4
Reconductor the 115 kV line between Newington and Newington Tap (1783)	Mar-20	4

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 9/21/20

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

Upgrade	Expected/ Actual In-Service	Present Stage
Separation of 115 kV DCT corresponding to the Bloomfield to South Meadow (1779) line and the Bloomfield to North Bloomfield (1777) line and add a breaker at Bloomfield 115 kV substation	Dec-17	4
Separation of 115 kV DCT corresponding to the Bloomfield to North Bloomfield (1777) line and the North Bloomfield – Rood Avenue – Northwest Hartford (1751) line and add a breaker at North Bloomfield 115 kV substation	Dec-17	4
Install a 115 kV 3% reactor on the 115 kV line between South Meadow and Southwest Hartford (1704)	Jul-20	4
Replace the existing 3% series reactors on the 115 kV lines between Southington and Todd (1910) and between Southington and Canal (1950) with a 5% series reactors	Dec-18	4
Replace the normally open 19T breaker at Southington 115 kV with a normally closed 3% series reactor	Jun-19	4
Add a 345 kV breaker in series with breaker 5T at Southington	May-17	4

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 9/21/20

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

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

* Replaces the NEEWS Central Connecticut Reliability Project

Southwest Connecticut (SWCT) Projects

Status as of 9/21/20

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

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

Southwest Connecticut Projects, cont.

Status as of 9/21/20

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

Upgrade	Expected/ Actual In-Service	Present Stage
Add two 14.4 MVAR capacitor banks at the West Brookfield substation	Dec-17	4
Add a new 115 kV line from Plumtree to Brookfield Junction	Jun-18	4
Reconductor the 115 kV line between West Brookfield and Brookfield Junction (1887)	Dec-20	3
Reduce the existing 25.2 MVAR capacitor bank at the Rocky River substation to 14.4 MVAR	Apr-17	4
Reconfigure the 1887 line into a three-terminal line (Plumtree - W. Brookfield - Shepaug)	May-18	4
Reconfigure the 1770 line into 2 two-terminal lines (Plumtree - Stony Hill and Stony Hill - Bates Rock)	May-18	4
Install a synchronous condenser (+25/-12.5 MVAR) at Stony Hill	Jun-18	4
Relocate an existing 37.8 MVAR capacitor bank at Stony Hill to the 25.2 MVAR capacitor bank side	May-18	4

Southwest Connecticut Projects, cont.

Status as of 9/21/20

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

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

Southwest Connecticut Projects, cont.

Status as of 9/21/20

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

Upgrade	**Expected/ Actual In-Service**	**Present Stage**
Add 2 x 20 MVAR capacitor banks at the Hawthorne substation	Mar-16	4
Upgrade the 115 kV bus at the Baird substation	Mar-18	4
Upgrade the 115 kV bus system and 11 disconnect switches at the Pequonnock substation	Dec-14	4
Add a 345 kV breaker in series with the existing 11T breaker at the East Devon substation	Dec-15	4
Rebuild the 115 kV lines from Baird to Congress (8809A / 8909B)	Dec-18	4
Rebuild the 115 kV lines from Housatonic River Crossing (HRX) to Barnum to Baird (88006A / 89006B)	Jun-21	3

Southwest Connecticut Projects, cont.

Status as of 9/21/20

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

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

Greater Boston Projects

Status as of 9/21/20

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

Upgrade	Expected/ Actual In-Service	Present Stage
Install new 345 kV line from Scobie to Tewksbury	Dec-17	4
Reconductor the Y-151 115 kV line from Dracut Junction to Power Street	Apr-17	4
Reconductor the M-139 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
Reconductor the N-140 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
Reconductor the F-158N 115 kV line from Wakefield Junction to Maplewood and associated work at Maplewood	Dec-15	4
Reconductor the F-158S 115 kV line from Maplewood to Everett	Jun-19	4
Install new 345 kV cable from Woburn to Wakefield Junction, install two new 160 MVAR variable shunt reactors and associated work at Wakefield Junction and Woburn*	May-22	3*
Refurbish X-24 69 kV line from Millbury to Northboro Road	Dec-15	4
Reconductor W-23W 69 kV line from Woodside to Northboro Road	Jun-19	4

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

Greater Boston Projects, cont.

Status as of 9/21/20

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

Upgrade	Expected/ Actual In-Service	Present Stage
Separate X-24 and E-157W DCT	Dec-18	4
Separate Q-169 and F-158N DCT	Dec-15	4
Reconductor M-139/211-503 and N-140/211-504 115 kV lines from Pinehurst to North Woburn tap	May-17	4
Install new 115 kV station at Sharon to segment three 115 kV lines from West Walpole to Holbrook	Oct-20	3
Install third 115 kV line from West Walpole to Holbrook	Oct-20	3
Install new 345 kV breaker in series with the 104 breaker at Stoughton	May-16	4
Install new 230/115 kV autotransformer at Sudbury and loop the 282-602 230 kV line in and out of the new 230 kV switchyard at Sudbury	Dec-17	4
Install a new 115 kV line from Sudbury to Hudson	Dec-23	2

Greater Boston Projects, cont.

Status as of 9/21/20

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

Upgrade	Expected/ Actual In-Service	Present Stage
Replace 345/115 kV autotransformer, 345 kV breakers, and 115 kV switchgear at Woburn	Dec-19	4
Install a 345 kV breaker in series with breaker 104 at Woburn	May-17	4
Reconfigure Waltham by relocating PARs, 282-507 line, and a breaker	Dec-17	4
Upgrade 533-508 115 kV line from Lexington to Hartwell and associated work at the stations	Aug-16	4
Install a new 115 kV 54 MVAR capacitor bank at Newton	Dec-16	4
Install a new 115 kV 36.7 MVAR capacitor bank at Sudbury	May-17	4
Install a second Mystic 345/115 kV autotransformer and reconfigure the bus	May-19	4
Install a 115 kV breaker on the East bus at K Street	Jun-16	4
Install 115 kV cable from Mystic to Chelsea and upgrade Chelsea 115 kV station to BPS standards	May-21	3
Split 110-522 and 240-510 DCT from Baker Street to Needham for a portion of the way and install a 115 kV cable for the rest of the way	Dec-20	3

Greater Boston Projects, cont.

Status as of 9/21/20

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

Upgrade	Expected/ Actual In-Service	Present Stage
Install a second 115 kV cable from Mystic to Woburn to create a bifurcated 211-514 line	May-22	3
Open lines 329-510/511 and 250-516/517 at Mystic and Chatham, respectively. Operate K Street as a normally closed station.	May-19	4
Upgrade Kingston to create a second normally closed 115 kV bus tie and reconfigure the 345 kV switchyard	Mar-19	4
Relocate the Chelsea capacitor bank to the 128-518 termination postion	Dec-16	4

Greater Boston Projects, cont.

Status as of 9/21/20

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

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

SEMA/RI Reliability Projects

Status as of 9/21/20

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

Project ID	Upgrade	Expected/ Actual In-Service	Present Stage
1714	Construct a new 115 kV GIS switching station (Grand Army) which includes remote terminal station work at Brayton Point and Somerset substations, and the looping in of the E-183E, F-184, X3, and W4 lines	Oct-20	3
1742	Conduct remote terminal station work at the Wampanoag and Pawtucket substations for the new Grand Army GIS switching station	Nov-20	3
1715	Install upgrades at Brayton Point substation which include a new 115 kV breaker, new 345/115 kV transformer, and upgrades to E183E, F184 station equipment	Oct-20	3
1716	Increase clearances on E-183E & F-184 lines between Brayton Point and Grand Army substations	Nov-19	4
1717	Separate the X3/W4 DCT and reconductor the X3 and W4 lines between Somerset and Grand Army substations; reconfigure Y2 and Z1 lines	Nov-19	4

SEMA/RI Reliability Projects, cont.

Status as of 9/21/20

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

Project ID	Upgrade	Expected/ Actual In-Service	Present Stage
1718	Add 115 kV circuit breaker at Robinson Ave substation and re-terminate the Q10 line	Dec-21	3
1719	Install 45.0 MVAR capacitor bank at Berry Street substation	Cancelled*	N/A
1720	Separate the N12/M13 DCT and reconductor the N12 and M13 between Somerset and Bell Rock substations	Nov-21	2
1721	Reconfigure Bell Rock to breaker-and-a-half station, split the M13 line at Bell Rock substation, and terminate 114 line at Bell Rock; install a new breaker in series with N12/D21 tie breaker, upgrade D21 line switch, and install a 37.5 MVAR capacitor	Dec-21	2
1722	Extend the Line 114 from the Dartmouth town line (Eversource- NGRID border) to Bell Rock substation	Dec-21	2
1723	Reconductor L14 and M13 lines from Bell Rock substation to Bates Tap	Cancelled*	N/A

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

SEMA/RI Reliability Projects, cont.

Status as of 9/21/20

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

Project ID	Upgrade	Expected/ Actual In-Service	Present Stage
1725	Build a new 115 kV line from Bourne to West Barnstable substations which includes associated terminal work	Dec-23	1
1726	Separate the 135/122 DCT from West Barnstable to Barnstable substations	Dec-21	1
1727	Retire the Barnstable SPS	Dec-21	1
1728	Build a new 115 kV line from Carver to Kingston substations and add a new Carver terminal	Dec-22	1
1729	Install a new bay position at Kingston substation to accommodate new 115 kV line	Dec-22	1
1730	Extend the 114 line from the Eversource/National Grid border to the Industrial Park Tap	Dec-23	1

SEMA/RI Reliability Projects, cont.

Status as of 9/21/20

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

Project ID	Upgrade	Expected/ Actual In-Service	Present Stage
1731	Install 35.3 MVAR capacitors at High Hill and Wing Lane substations	Dec-21	2
1732	Loop the 201-502 line into the Medway substation to form the 201-502N and 201-502S lines	Jan-23	1
1733	Separate the 325/344 DCT lines from West Medway to West Walpole substations	Cancelled**	N/A
1734	Reconductor and upgrade the 112 Line from the Tremont substation to the Industrial Tap	Jun-18	4
1736	Reconductor the 108 line from Bourne substation to Horse Pond Tap*	Oct-18	4
1737	Replace disconnect switches on 323 line at West Medway substation and replace 8 line structures	Dec-20	3

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

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

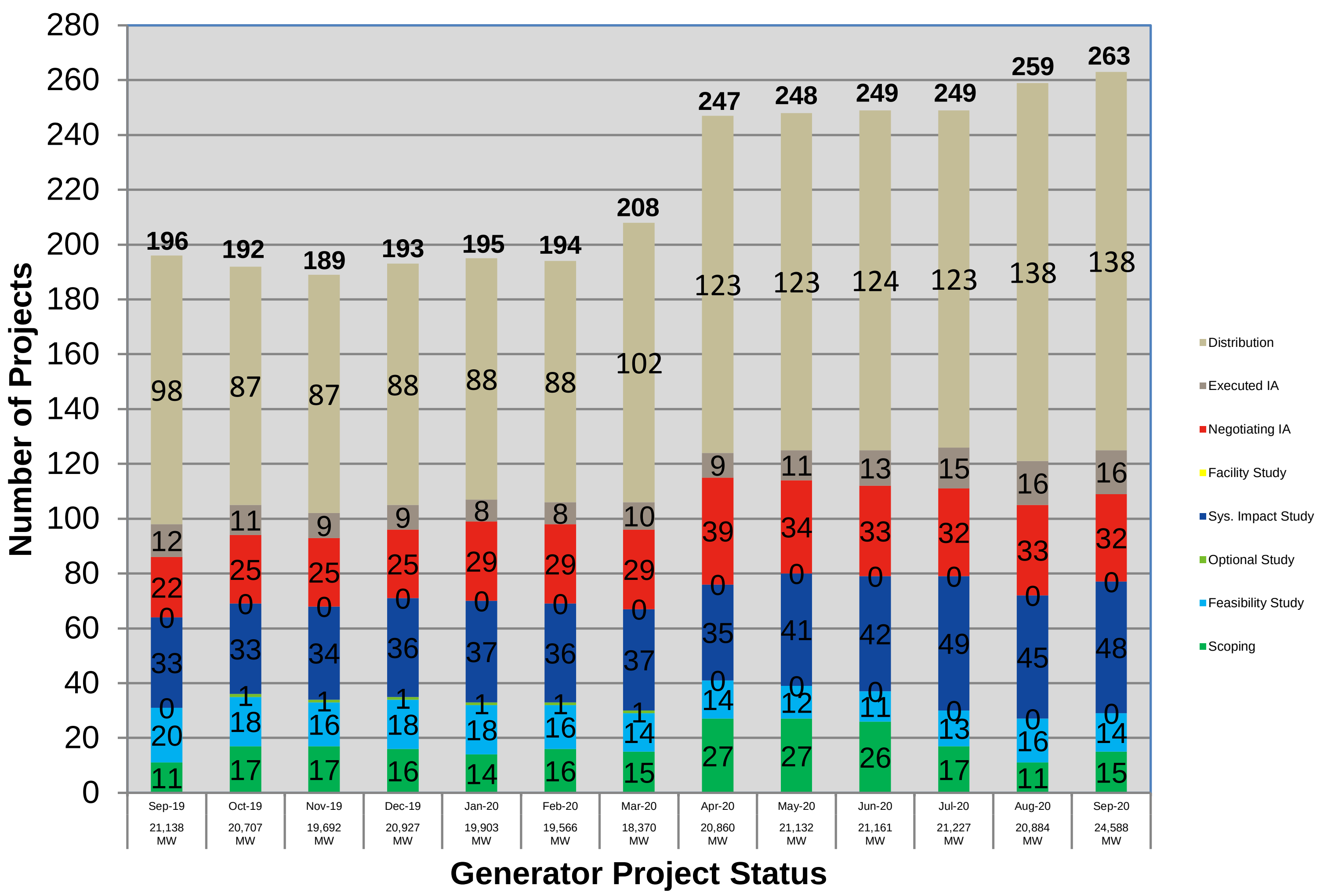
SEMA/RI Reliability Projects, cont.

Status as of 9/21/20

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

Project ID	Upgrade	Expected/ Actual In-Service	Present Stage
1741	Rebuild the Middleborough Gas and Electric portion of the E1 line from Bridgewater to Middleborough	Apr-19	4
1782	Reconductor the J16S line	Dec-21	2
1724	Replace the Kent County 345/115 kV transformer	Mar-22	2
1789	West Medway 345 kV circuit breaker upgrades	Dec-21	3
1790	Medway 115 kV circuit breaker replacements	Dec-21	3

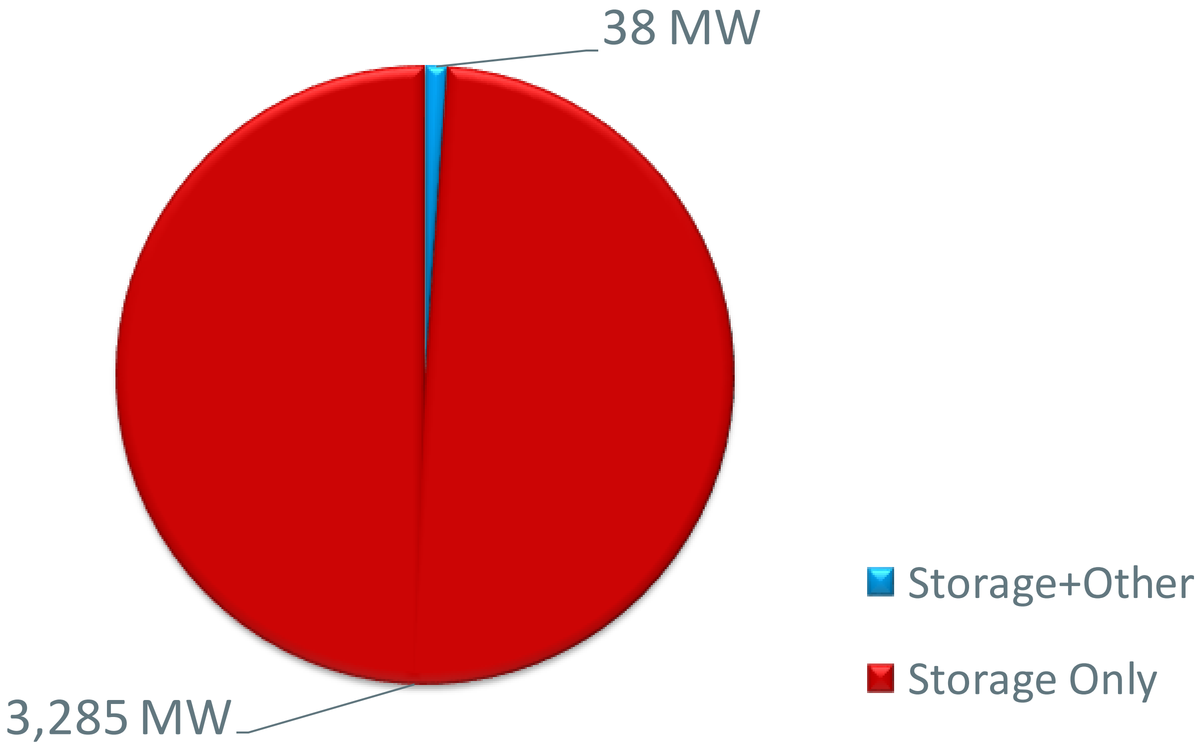
Status of Tariff Studies



Note: September 2020 is based on partial data.
As of September 2020, there are 4 ETU's in Scoping, 1 in FS, 3 in SIS, 0 in FAC, 1 Negotiating IA, and 1 with Executed IA.
https://irtt.iso-ne.com/external.aspx

What is in the Queue (as of September 16, 2020)

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



OPERABLE CAPACITY ANALYSIS

Fall 2020 Analysis

Fall 2020 Operable Capacity Analysis

50/50 **Load Forecast** (Reference)	**Oct. - 2020[2] CSO (MW)**	**Oct. - 2020[2] SCC (MW)**
Operable Capacity MW [1]	30,401	30,837
Active Demand Capacity Resource (+) [5]	411	425
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,096	1,096
Non Commercial Capacity (+)	19	19
Non Gas-fired Planned Outage MW (-)	6,317	7,100
Gas Generator Outages MW (-)	1,606	1,843
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	21,204	20,634
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	16,459	16,459
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	18,764	18,764
Operable Capacity Margin	2,440	1,870

[1] Operable Capacity is based on data as of **September 28, 2020** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **September 28, 2020.**

[2] Load forecast that is based on the 2020 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **October 17, 2020.**

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

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

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

Fall 2020 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	Oct.- 2020[2] CSO (MW)	Oct. - 2020[2] SCC (MW)
Operable Capacity MW [1]	30,401	30,837
Active Demand Capacity Resource (+) [5]	411	425
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,096	1,096
Non Commercial Capacity (+)	19	19
Non Gas-fired Planned Outage MW (-)	6,317	7,100
Gas Generator Outages MW (-)	1,606	1,843
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	21,204	20,634
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	17,001	17,001
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	19,306	19,306
Operable Capacity Margin	1,898	1,328

[1] Operable Capacity is based on data as of **September 28, 2020** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **September 28, 2020.**

[2] Load forecast that is based on the 2020 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **October 17, 2020.**

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

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

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

Fall 2020 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

October 1, 2020 - 50-50 FORECAST using CSO

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

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW [1]	Active Capacity Demand MW [2]	EXTERNAL NODE AVAIL CAPACITY MW [3]	NON COMMERCIAL CAPACITY MW [4]	NON-GAS PLANNED OUTAGES CSO MW [5]	GAS GENERATOR OUTAGES CSO MW [6]	ALLOWANCE FOR UNPLANNED OUTAGES MW [7]	GAS AT RISK MW [8]	NET OPCAP SUPPLY MW [9]	PEAK LOAD FORECAST MW [10]	OPER RESERVE REQUIREMENT MW [11]	NET LOAD OBLIGATION MW [12]	OPCAP MARGIN MW [13]
10/10/2020	30401	411	1096	19	6317	1382	2800	0	21428	16076	2305	18381	3047
10/17/2020	**30401**	**411**	**1096**	**19**	**6317**	**1606**	**2800**	**0**	**21204**	**16459**	**2305**	**18764**	**2440**
10/24/2020	30401	411	996	19	5866	815	2800	0	22346	16677	2305	18982	3364
10/31/2020	30476	510	1025	19	4209	1459	3600	0	22762	16798	2305	19103	3659
11/7/2020	30476	510	1025	19	2761	1292	3600	0	24377	17160	2305	19465	4912
11/14/2020	30476	510	1025	19	2770	1469	3600	0	24191	17936	2305	20241	3950
11/21/2020	30476	510	1025	19	1822	1544	3600	0	25064	18694	2305	20999	4065

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. The active demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity Market (FCM). These resources will have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
4. New resources and generator improvements that have acquired a CSO but have not become commercial.
5. Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.
6. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. Net OpCap Supply MW Available (1 + 2 + 3 + 4 - 5 - 6 - 7 - 8 = 9)
10. Peak Load Forecast as provided in the 2020 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 25,125 and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV)
11. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
12. Total Net Load Obligation per the formula(10 + 11 = 12)
13. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (9 - 12 = 13)

Fall 2020 Operable Capacity Analysis

90/10 Forecast (Extreme)

ISO-NE OPERABLE CAPACITY ANALYSIS

October 1, 2020 - 90-10 FORECAST using CSO

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

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW [1]	Active Capacity Demand MW [2]	EXTERNAL NODE AVAIL CAPACITY MW [3]	NON COMMERCIAL CAPACITY MW [4]	NON-GAS PLANNED OUTAGES CSO MW [5]	GAS GENERATOR OUTAGES CSO MW [6]	ALLOWANCE FOR UNPLANNED OUTAGES MW [7]	GAS AT RISK MW [8]	NET OPCAP SUPPLY MW [9]	PEAK LOAD FORECAST MW [10]	OPER RESERVE REQUIREMENT MW [11]	NET LOAD OBLIGATION MW [12]	OPCAP MARGIN MW [13]
10/10/2020	30401	411	1096	19	6317	1382	2800	0	21428	16607	2305	18912	2516
10/17/2020	**30401**	**411**	**1096**	**19**	**6317**	**1606**	**2800**	**0**	**21204**	**17001**	**2305**	**19306**	**1898**
10/24/2020	30401	411	996	19	5866	815	2800	0	22346	17224	2305	19529	2817
10/31/2020	30476	510	1025	19	4209	1459	3600	0	22762	17349	2305	19654	3108
11/7/2020	30476	510	1025	19	2761	1292	3600	0	24377	17721	2305	20026	4351
11/14/2020	30476	510	1025	19	2770	1469	3600	129	24062	18518	2305	20823	3239
11/21/2020	30476	510	1025	19	1822	1544	3600	855	24209	19296	2305	21601	2608

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. The active demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity Market (FCM). These resources will have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
4. New resources and generator improvements that have acquired a CSO but have not become commercial.
5. Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.
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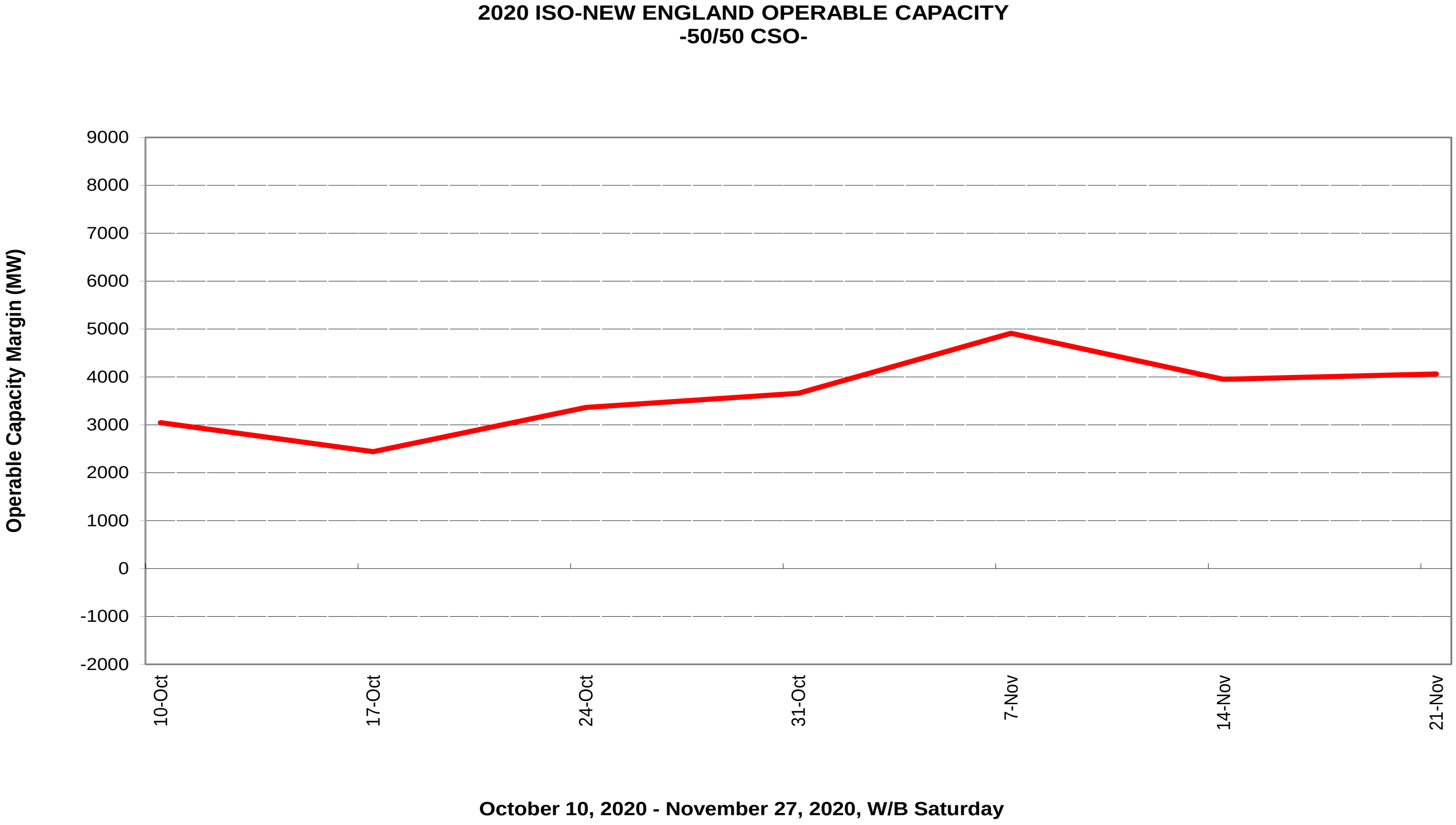
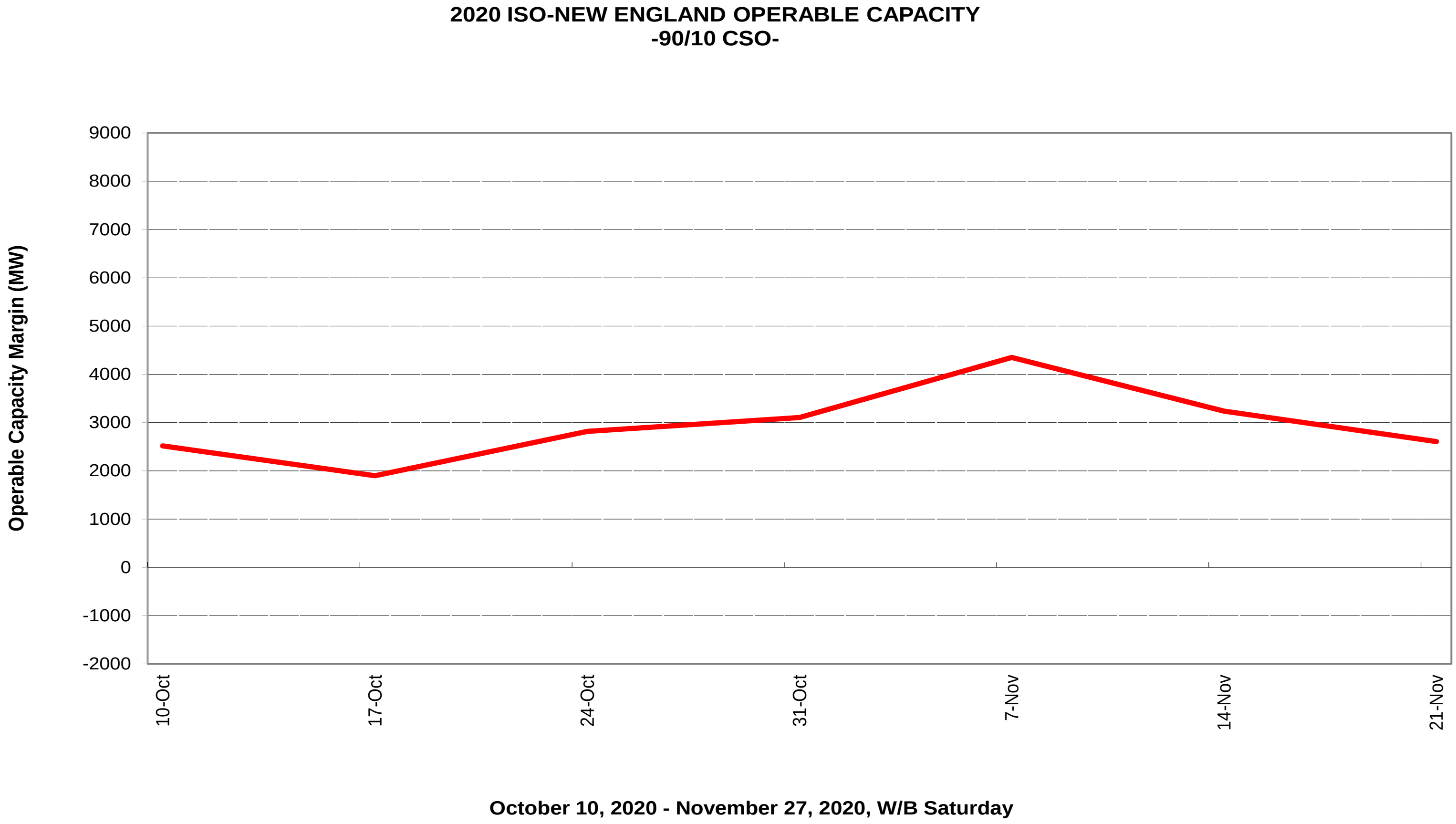
7. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. Net OpCap Supply MW Available (1 + 2 + 3 + 4 - 5 - 6 - 7 - 8 = 9)
10. Peak Load Forecast as provided in the 2020 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 27,084 and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV)
11. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
12. Total Net Load Obligation per the formula(10 + 11 = 12)
13. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (9 - 12 = 13)

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

Fall 2020 Operable Capacity Analysis
50/50 Forecast (Reference)



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



OPERABLE CAPACITY ANALYSIS

Preliminary Winter 2020/21 Analysis

Preliminary Winter 2020/21 Operable Capacity Analysis

50/50 **Load Forecast** (Reference)	**Jan. - 2020**[2] **CSO (MW)**	**Jan. - 2020**[2] **SCC (MW)**
Operable Capacity MW [1]	30,459	33,692
Active Demand Capacity Resource (+) [5]	533	381
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,025	1,025
Non Commercial Capacity (+)	19	19
Non Gas-fired Planned Outage MW (-)	298	301
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	3,893	4,301
Net Capacity (NET OPCAP SUPPLY MW)	25,045	27,715
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,166	20,166
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,471	22,471
Operable Capacity Margin	2,574	5,244

[1] Operable Capacity is based on data as of **September 28, 2020** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **September 28, 2020.**

[2] Load forecast that is based on the 2020 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 2, 2021.**

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

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

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

Preliminary Winter 2020/21 Operable Capacity Analysis

90/10 **Load Forecast** (Extreme)	**Jan. - 2020**^{2} **CSO (MW)**	**Jan. - 2020**^{2} **SCC (MW)**
Operable Capacity MW [1]	30,459	33,692
Active Demand Capacity Resource (+) [5]	533	381
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,025	1,025
Non Commercial Capacity (+)	19	19
Non Gas-fired Planned Outage MW (-)	298	301
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	4,595	5,077
Net Capacity (NET OPCAP SUPPLY MW)	24,343	26,939
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,806	20,806
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,111	23,111
Operable Capacity Margin	1,232	3,828

[1] Operable Capacity is based on data as of **September 28, 2020** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **September 28, 2020.**

[2] Load forecast that is based on the 2020 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 2, 2021.**

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

Preliminary Winter 2020/21 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

October 1, 2020 - 50-50 FORECAST using CSO

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

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW [1]	Active Capacity Demand MW [2]	EXTERNAL NODE AVAIL CAPACITY MW [3]	NON COMMERCIAL CAPACITY MW [4]	NON-GAS PLANNED OUTAGES CSO MW [5]	GAS GENERATOR OUTAGES CSO MW [6]	ALLOWANCE FOR UNPLANNED OUTAGES MW [7]	GAS AT RISK MW [8]	NET OPCAP SUPPLY MW [9]	PEAK LOAD FORECAST MW [10]	OPER RESERVE REQUIREMENT MW [11]	NET LOAD OBLIGATION MW [12]	OPCAP MARGIN MW [13]
11/28/2020	30476	510	1025	19	1536	0	3600	2038	24856	19009	2305	21314	3542
12/5/2020	30459	533	1025	19	339	264	3200	2215	26018	19313	2305	21618	4400
12/12/2020	30459	533	1025	19	350	267	3200	2419	25800	19325	2305	21630	4170
12/19/2020	30459	533	1025	19	309	0	3200	2909	25618	19390	2305	21695	3923
12/26/2020	30459	533	1025	19	298	0	3200	3270	25268	19390	2305	21695	3573
1/2/2021	**30459**	**533**	**1025**	**19**	**298**	**0**	**2800**	**3893**	**25045**	**20166**	**2305**	**22471**	**2574**
1/9/2021	30459	533	1025	19	298	0	2800	3888	25050	20166	2305	22471	2579
1/16/2021	30459	533	1025	19	368	0	2800	3737	25131	20166	2305	22471	2660
1/23/2021	30459	533	1025	19	293	0	2800	3270	25673	19933	2305	22238	3435
1/30/2021	30459	533	1025	19	293	0	3100	2958	25685	19933	2305	22238	3447
2/6/2021	30459	533	1025	19	293	0	3100	2647	25996	19652	2305	21957	4039
2/13/2021	30459	533	1025	19	753	0	3100	2336	25847	19622	2305	21927	3920
2/20/2021	30459	533	1025	19	764	0	3100	1869	26303	19346	2305	21651	4652
2/27/2021	30459	533	1025	19	1068	0	2200	1557	27211	18308	2305	20613	6598
3/6/2021	30459	533	1025	19	1074	0	2200	1246	27516	17941	2305	20246	7270
3/13/2021	30459	533	1025	19	1080	0	2200	623	28133	17736	2305	20041	8092
3/20/2021	30459	533	1025	19	1339	508	2200	0	27989	17352	2305	19657	8332
3/27/2021	30446	537	1025	19	864	239	2700	0	28224	16759	2305	19064	9160

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
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3. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
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9. Net OpCap Supply MW Available (1 + 2 + 3 + 4 - 5 - 6 - 7 - 8 = 9)
10. Peak Load Forecast as provided in the 2020 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 25,125 and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV)
11. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
12. Total Net Load Obligation per the formula(10 + 11 = 12)
13. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (9 - 12 = 13)

Preliminary Winter 2020/21 Operable Capacity Analysis

90/10 Forecast (Extreme)

ISO-NE OPERABLE CAPACITY ANALYSIS

October 1, 2020 - 90-10 FORECAST using CSO

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

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW [1]	Active Capacity Demand MW [2]	EXTERNAL NODE AVAIL CAPACITY MW [3]	NON COMMERCIAL CAPACITY MW [4]	NON-GAS PLANNED OUTAGES CSO MW [5]	GAS GENERATOR OUTAGES CSO MW [6]	ALLOWANCE FOR UNPLANNED OUTAGES MW [7]	GAS AT RISK MW [8]	NET OPCAP SUPPLY MW [9]	PEAK LOAD FORECAST MW [10]	OPER RESERVE REQUIREMENT MW [11]	NET LOAD OBLIGATION MW [12]	OPCAP MARGIN MW [13]
11/28/2020	30476	510	1025	19	1536	0	3600	2990	23904	19618	2305	21923	1981
12/5/2020	30459	533	1025	19	339	264	3200	3244	24989	19930	2305	22235	2754
12/12/2020	30459	533	1025	19	350	267	3200	3447	24772	19942	2305	22247	2525
12/19/2020	30459	533	1025	19	309	0	3200	4073	24454	20009	2305	22314	2140
12/26/2020	30459	533	1025	19	298	0	3200	4463	24075	20009	2305	22314	1761
1/2/2021	**30459**	**533**	**1025**	**19**	**298**	**0**	**2800**	**4595**	**24343**	**20806**	**2305**	**23111**	**1232**
1/9/2021	30459	533	1025	19	298	0	2800	4732	24206	20806	2305	23111	1095
1/16/2021	30459	533	1025	19	368	0	2800	4516	24352	20806	2305	23111	1241
1/23/2021	30459	533	1025	19	293	0	2800	4204	24739	20566	2305	22871	1868
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2/13/2021	30459	533	1025	19	753	0	3100	3426	24757	20247	2305	22552	2205
2/20/2021	30459	533	1025	19	764	0	3100	2803	25369	19963	2305	22268	3101
2/27/2021	30459	533	1025	19	1068	0	2200	2336	26432	18897	2305	21202	5230
3/6/2021	30459	533	1025	19	1074	0	2200	2180	26582	18520	2305	20825	5757
3/13/2021	30459	533	1025	19	1080	0	2200	1557	27199	18309	2305	20614	6585
3/20/2021	30459	533	1025	19	1339	508	2200	582	27407	17915	2305	20220	7187
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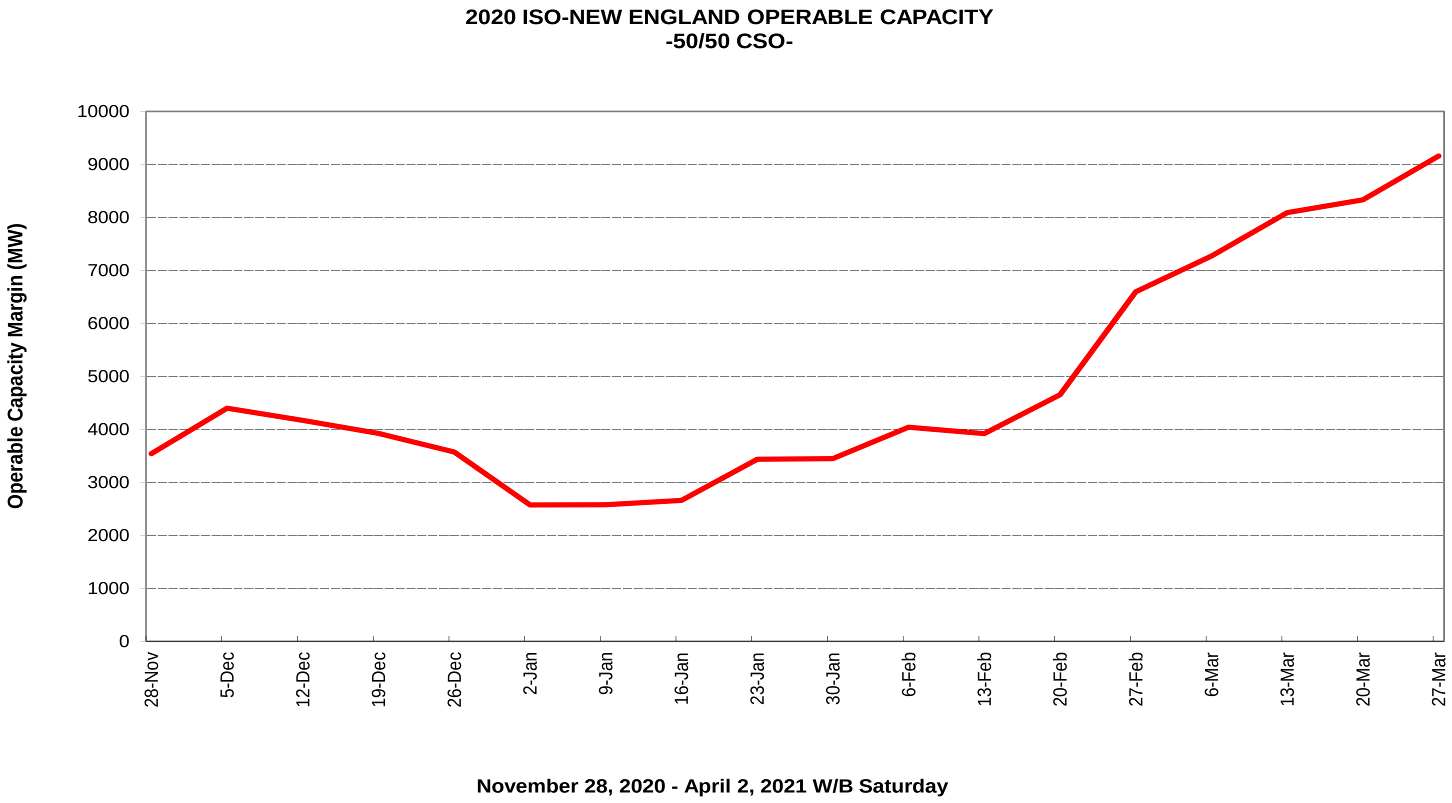
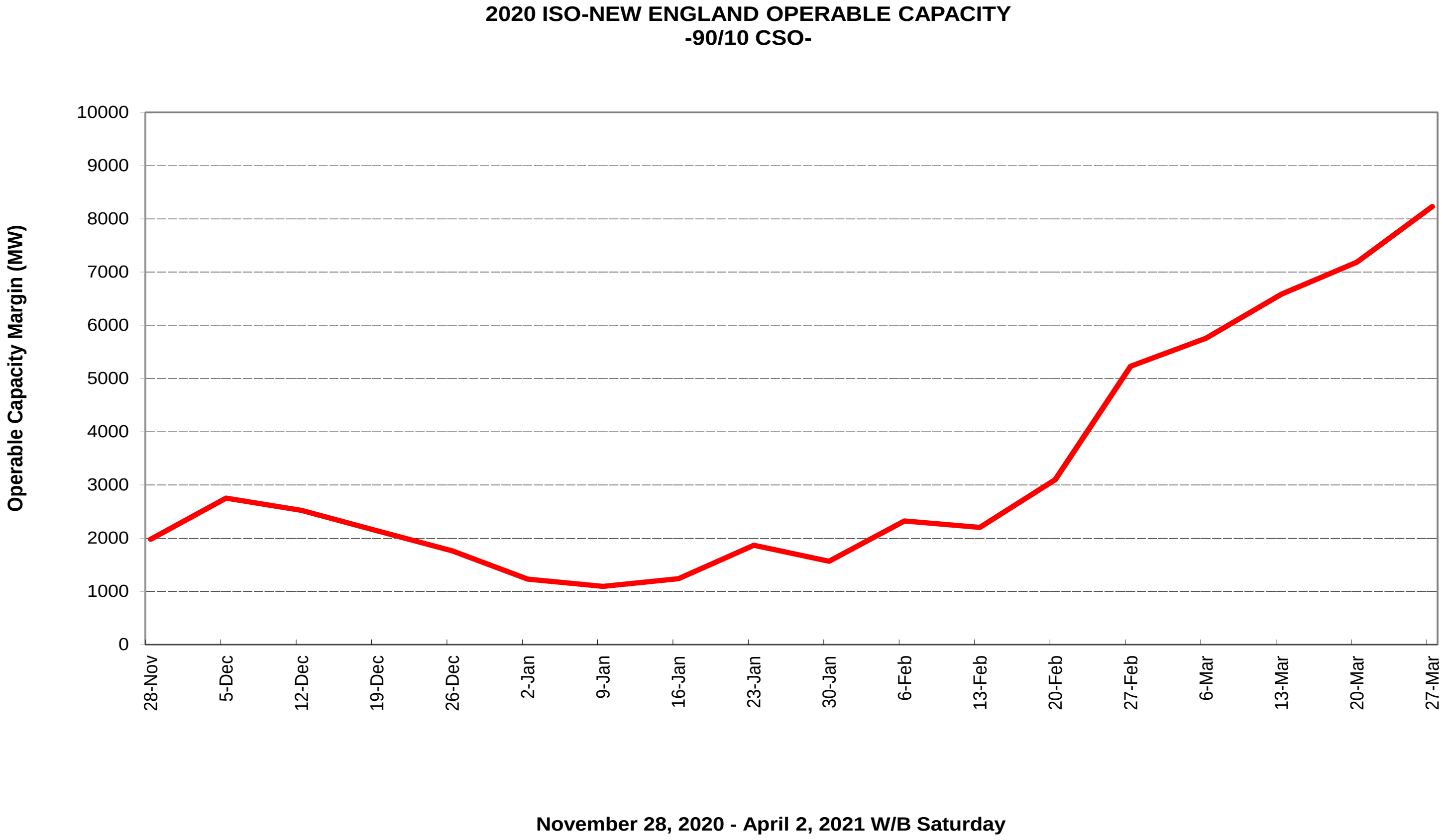
Preliminary Winter 2020/21 Operable Capacity Analysis

50/50 Forecast (Reference)



Preliminary Winter 2020/21 Operable Capacity Analysis

90/10 Forecast (Extreme)



OPERABLE CAPACITY ANALYSIS

Appendix

Possible Relief Under OP4: Appendix A

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

NOTES:

1. Based on Summer Ratings. Assumes 25% of total MW Settlement Only resources <5 MW will be available and respond.
2. The actual load relief obtained is highly dependent on circumstances surrounding the appeals, including timing and the amount of advanced notice that can be given.
3. The MW values are based on a 25,000 MW system load and verified by the most recent voltage reduction test.
4. EEA Levels are described in Attachment 1 to NERC Reliability Standard EOP-011 - Emergency Operations

Possible Relief Under OP4: Appendix A

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

NOTES:

1. Based on Summer Ratings. Assumes 25% of total MW Settlement Only resources <5 MW will be available and respond.
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3. The MW values are based on a 25,000 MW system load and verified by the most recent voltage reduction test
4. EEA Levels are described in Attachment 1 to NERC Reliability Standard EOP-011 - Emergency Operations

SEPTEMBER 17, 2020

ISO New England's Draft 2021 Annual Work Plan

For Discussion at the October 1, 2020, NEPOOL Participants Committee Meeting

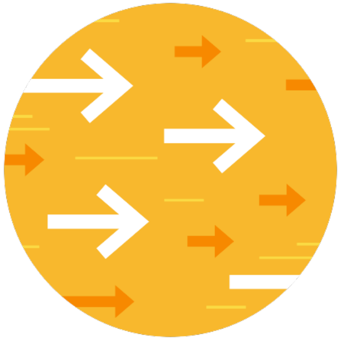
Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

2021 Objectives and Highlights

Innovating for the changing grid; adjusting to impacts of recent events; advancing operational improvements and managing risks

- Notable initiatives focus on innovation for the clean-energy transition across markets, planning, operations, and software structures
  - Energy Security Initiatives (ESI) key projects
  - New England's Future Grid Initiative
  - Transmission planning for an evolving grid
  - Evaluating impacts of shifting net peak loads



- Additional priorities align with recent events
  - 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
  - Moving the margining and settling of the Financial Transmission Rights market to a clearinghouse
- The foremost business implementation/capital projects improve speed and efficiency; mitigate risks
  - Implementing nGEM day-ahead market clearing software upgrades
  - Enhancing cybersecurity tools to protect against increased intrusion attempts

Unknown Impacts of 2021 Factors

The ISO must remain flexible during this uncertain time while performing well in our day-to-day operations

- **COVID-19 impact on business**:
  To date, all of the ISO's reliability, markets, and planning functions have proceeded as usual, and our lines of communication have remained open
  - Unknown long-term effect of continued pandemic on new cross-functional and/or complex initiatives
- **FERC actions**: Unknown timing and topics for possible FERC orders or NOPRs; November 2020 election results could also potentially shift regulatory priorities
  - **FERC Order No. 2222 on Distributed Energy Resources**, issued September 17, 2020, will need to be assessed for impacts on the overall work plan

NOTABLE INITIATIVES

Innovating for a changing grid

Develop Additional Components of ESI

Projects relating to the region's energy-security needs continue to be a priority

- FERC's order on the April 2020 ESI filing will provide the foundation for the ISO's next steps
  - Approval of core design of day-ahead ancillary services is key
- Subject to that approval, the ISO is continuing its efforts to prepare and advance the additional components of ESI:
  - Market power mitigation framework
  - Seasonal forward market construct
  - Detailed design and conforming rule changes
- If FERC changes the core design or schedule, the ISO will adjust plans accordingly

Develop Additional Components of ESI, cont'd

Meet anticipated FERC deadlines for designing ESI market power mitigation framework

- The ISO is conducting a **market power assessment** (MPA) to identify the extent to which market power could be exercised with ESI day-ahead ancillary services
  - The MPA is a time-consuming and technical undertaking that involves multiple departments and significant resources
- The ISO will then develop the **mitigation market rules and procedures**, guided by the results of the MPA and input from both the internal and external market monitors and stakeholders
- Significant resources are being allocated to fulfill this schedule
  - Complete initial MPA (late 2020)
  - Assess results and design framework to mitigate market power (2021)
  - Stakeholder process and filing of final MPA and mitigation rules (2021)

Develop Additional Components of ESI, cont'd

Seasonal forward market construct, design details, and conforming changes

- The ISO is targeting late 2021 to have further discussions with stakeholders on its developments for a **seasonal forward market** that complements the ESI day-ahead ancillary services
  - Work is subject to the FERC order; core design of the ancillary markets must first be set to determine design of seasonal forward market

- With the implementation (go-live) of the ESI day-ahead ancillary services planned for June 2024, the ISO is working over the next few years to complete all **design, technical, and implementation/integration details**
  - Multiple conforming-change projects to the market rules in areas such as Net Commitment Period Compensation, financial assurance requirements, and more are likely to be brought through stakeholder process in 2022-2023 before filing with FERC

New England's Future Grid Initiative

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

- The ISO is engaging with market participants and state entities, including NESCOE, on this high-priority initiative
- Stakeholder meetings in 2020 are exploring this initiative on two tracks that are contemplating a reliable, clean-energy future grid:
  - **Future Grid Reliability Study**: Assess the future state of the power system by: defining scenarios; studying whether the ISO can operate reliably under status-quo mechanisms; considering what products and attributes are missing; and discussing what market changes could be developed in response
    - The ISO is supporting stakeholder discussions and preparing to assist with requested studies; the ISO is working with stakeholders to shape its scope of engagement on this track for 2021
  - **Pathways to the Future Grid**: Regional identification, exploration, and evaluation of potential market frameworks that may help support the evolution of New England's power grid
    - In 2021, ISO resources are dedicated to evaluating market-framework options

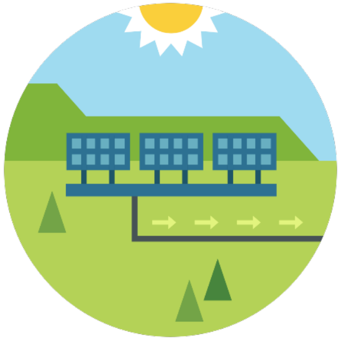
Transmission Planning for the Evolving Grid

As future-grid trends continue to accelerate, the ISO must also examine new transmission study challenges that will arise

- In late 2020 and extending into **2021**, the ISO will consider and discuss with stakeholders proposed refinements to transmission planning assumptions that better reflect long-term trends, such as increased amounts of distributed-energy resources (DERs), renewable resources, and energy storage
  - Different system conditions could drive transmission planning needs
  - Differing load levels, times of day, and times of year will need to be considered based on changing resource-mix characteristics
  - Data collection will need to be expanded, including increased data on load and DERs from distribution owners, to accurately model the system
- Proposed changes in assumptions could be used in future studies such as Needs Assessments and Competitive Solution Process/Solutions Studies
  - Some studies may begin using new assumptions in 2021

Evaluate Impacts of Shifting Peak Loads

The summer daily peak is shifting to later in the day



- The ISO is reviewing the effect of projected behind-the-meter photovoltaics (BTM PV) growth on net peak loads to determine if changes are warranted to how the region's capacity requirements are calculated or how resources' reliability contributions are measured
  - The ISO is analyzing these effects using peak-hour scenarios and BTM PV projections
- In addition, the ISO is performing an initial study of effective load carrying capability (ELCC) to analyze the capacity value of adding renewable generation and energy storage resources
  - ELCC is a dynamic method for measuring resources' contribution to reliably serving load and could play an important role for planning and markets as the resource mix evolves
- Once these analyses are more fully developed, the ISO plans to discuss the findings with stakeholders and consider how the results may be used to update our processes
- These early stages of analyses began in 2020 and will continue through 2021

NOTABLE INITIATIVES

Adjusting to impacts of recent events

Order 1000/Boston 2028 RFP: Lessons Learned

Refining the competitive transmission solicitation process

- Following the conclusion of the Boston 2028 RFP process, the ISO has committed to reviewing lessons learned from its first competitive transmission solicitation process
- While the process functioned as intended with the selection of a least-cost, reliable solution, a lessons-learned exercise will provide the ISO and stakeholders the opportunity to discuss some possible areas for improvement. In Q4 2020, the ISO will:
  - Hold a lessons-learned session with stakeholders
  - Offer one-on-one sessions with Qualified Transmission Project Sponsors that responded to the Boston 2028 RFP where specific questions regarding their proposals or the process can be discussed
- **For 2021**, the ISO is allotting resources to support additional discussions and for assessing any future changes, as needed

Load Forecasting Enhancements

Continuing improvements to operational and long-term planning forecasts

- **Real-time operational forecasts**: In 2019, the ISO implemented enhancements to more accurately forecast the impact of PV installations; in 2020, the ISO began producing a weekly analysis of the estimated impact on region-wide system demand attributable to societal changes in response to COVID-19
  - In 2021, the ISO will continue to share with participants what our operators observe in real-time and make adjustments as necessary as the pandemic evolves
  - The ISO also plans to build on its PV forecast by including more cities and data
- **Long-term planning forecasts**: The ISO will develop the long-term peak-load forecast for CELT 2021, which will reflect expected economic impacts of the pandemic
  - The ISO will use Moody's October 2020 macroeconomic outlook and other economic indicators such as employment numbers
  - Discussions are ongoing with industry experts regarding emerging technologies/trends and methods of incorporating these into the forecast

Submission of FTRs for Clearing

Addressing default risk in the Financial Transmission Rights (FTR) market for the ISO and market participants

- Major defaults in other RTO FTR markets in North America have occurred in recent years, where lack of appropriate margining and inability to liquidate positions resulted in other market participants bearing the cost of the defaults
  - The ability to liquidate positions and set margin is needed to manage default risk in the ISO’s FTR market but requires more robust infrastructure and expertise than we can offer
- Therefore, the ISO is working toward moving the margining and settlement of FTRs to a third-party—potentially Nodal Exchange Clearing—who will calculate the collateral requirements and employ twice-daily margining and settlement for the ISO’s FTR customers
  - The ISO will continue to administer FTR auctions, but upon completion, FTR awards will be novated to location-specific futures contracts on the exchange
  - The ISO will be a counterparty in each of the futures contracts novated; the counterparty default risk from FTR portfolios is isolated from the ISO’s market participants
- The project is targeted to kick off in Q2 2021 and possibly extend into 2022
  - The timeline is dependent on the ISO obtaining financing for the margin requirements as the counterparty, FERC discussions, the stakeholder process, and finalization of rules

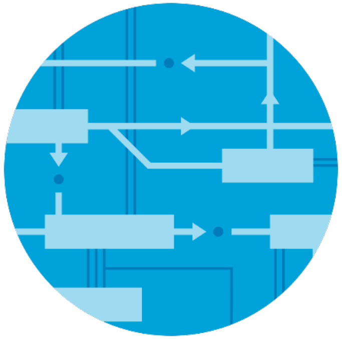
NOTABLE INITIATIVES

Advancing operational improvements and managing risks

nGEM Day-Ahead Market Clearing Engine Implementation

This is one project within the broader nGEM Program

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



Enhance Cybersecurity Tools

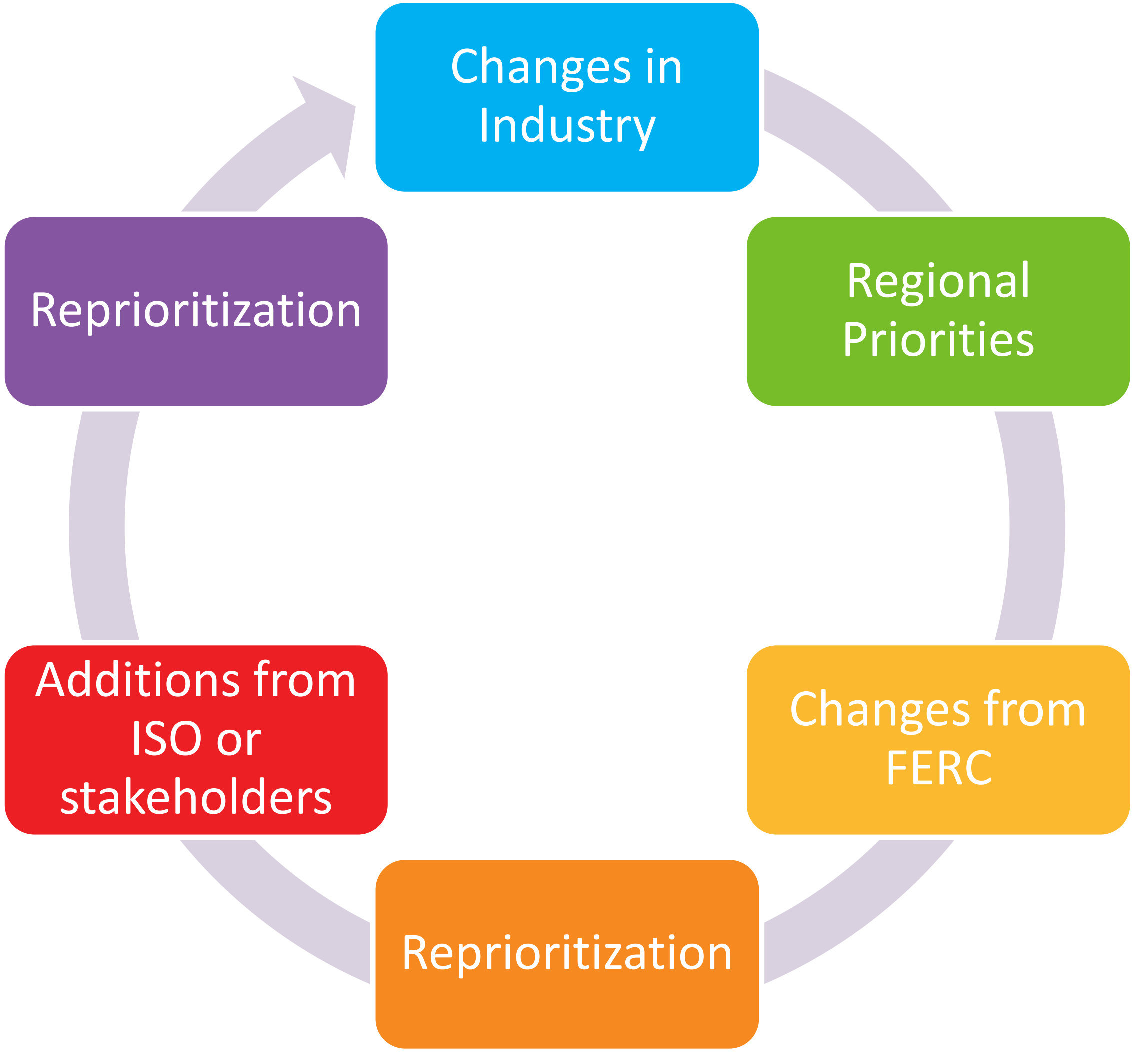
While a key focus for the ISO over past five years, continued security enhancements are needed to mitigate rise in intrusion attempts by state actors

- **Identity & Access Management (IAM)** replaces the ISO's access rights application that records approval of users to thousands of ISO assets (e.g., applications, badged physical access, etc.)
  - IAM is the foundation of the ISO's cybersecurity program: improves the functionality and security associated with logical and physical access management, and maintains compliance of these functions with NERC Critical Infrastructure Protection standards
  - Implementation is major undertaking, affecting dozens of business processes and every member of workforce
- **Security Information and Event Management (SIEM)** collects and correlates logs from hundreds of servers, network devices, and the applications running on them
  - New system allows in-depth analysis of logs for monitoring and alerting on security events
- **Ongoing refinements to phishing attack tests** will be developed to enhance phishing-risk metrics for the company and update employee training, awareness, and testing measures appropriately
- These projects will be completed in 2021

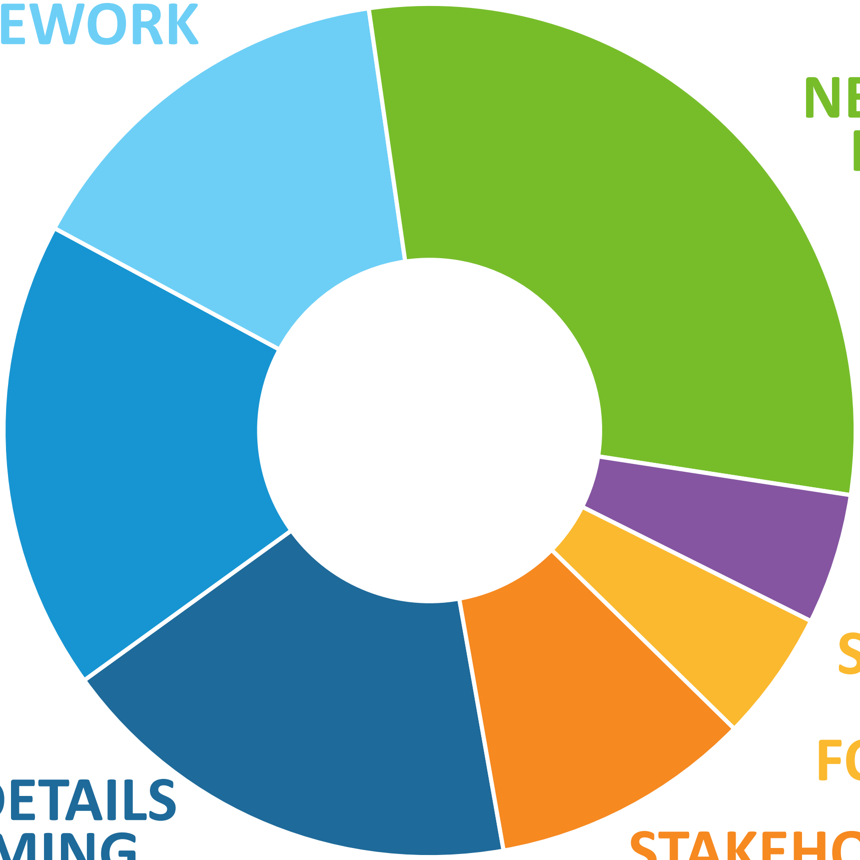
WORK PLAN PRIORITIZATION

Prioritization Process

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



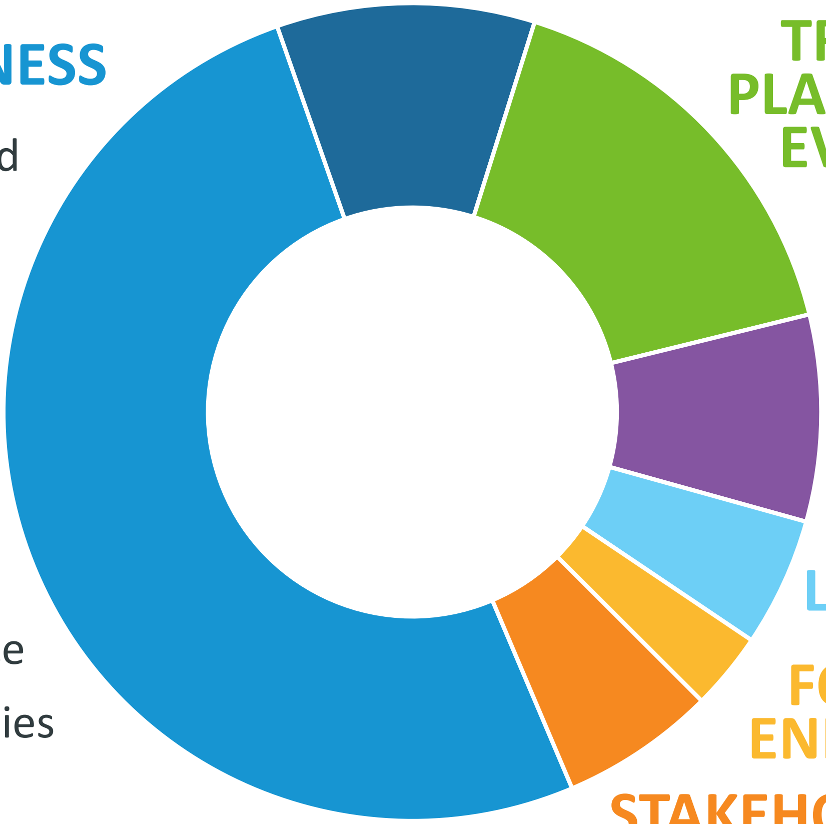
Markets-Related Priorities Include:



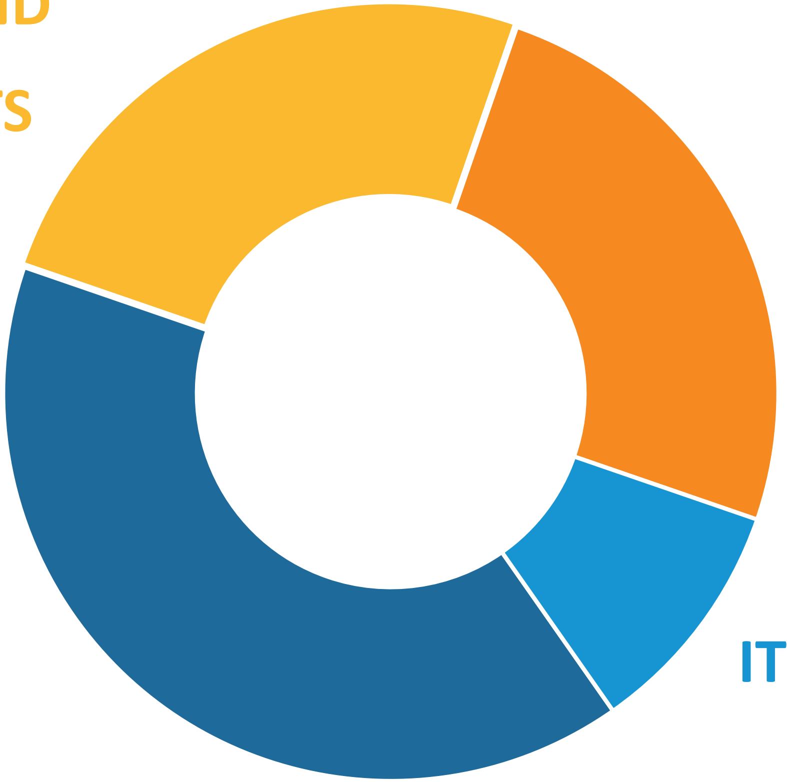
Planning/Operations Priorities Include:

CONTINUING BUSINESS

- Generation/Distributed Generation (DG) Interconnection and Transmission Planning
- Administer FCA #15 and FCM-related modeling
- NERC/FERC Compliance
- Annual Economic Studies



Capital Project Priorities Include:



APPLICATION AND DATABASE ENHANCEMENTS

- FCTS
- IMM Data Analysis
- Scheduling
- PMU
- Historian
- Market Simulator

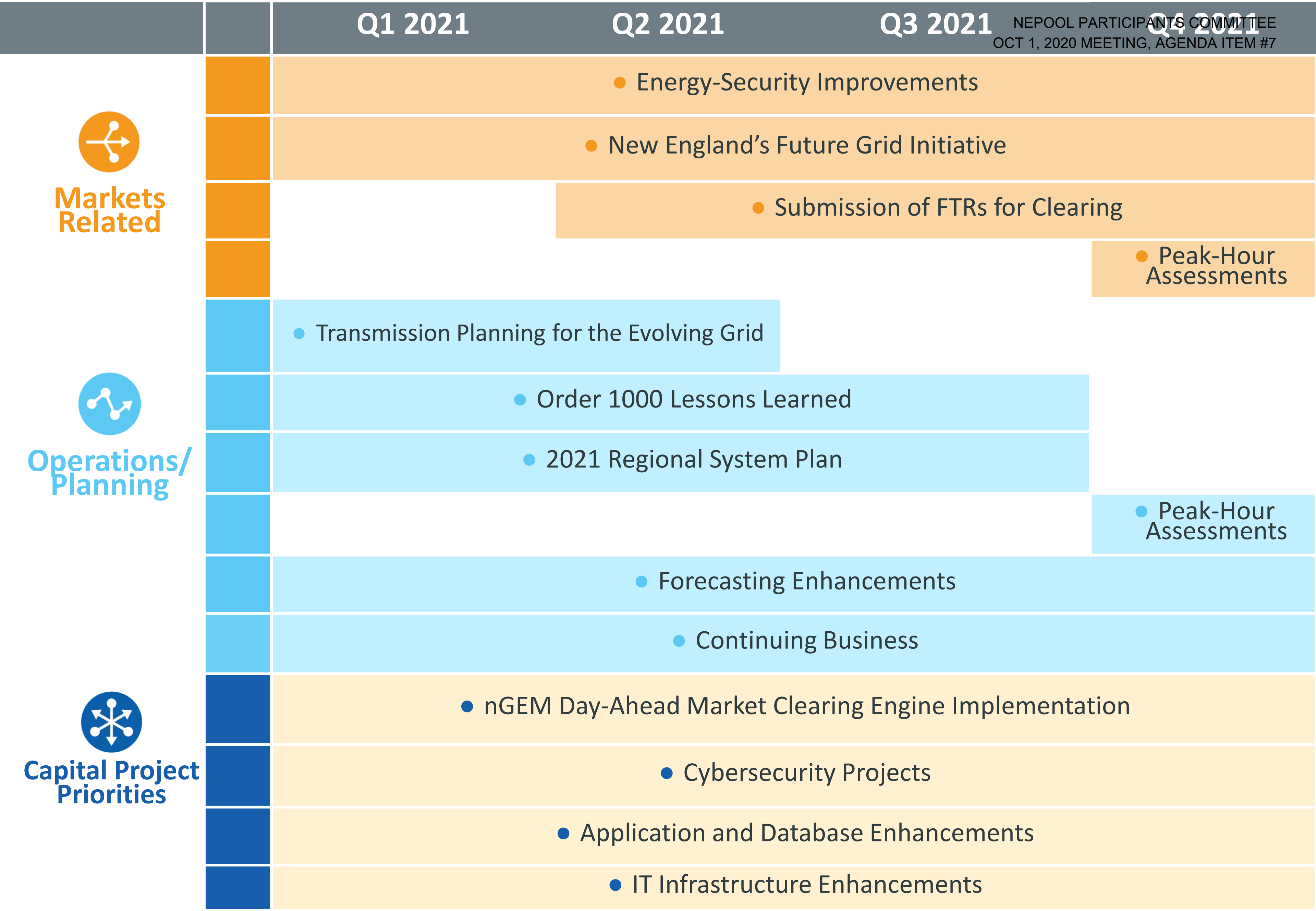
CYBERSECURITY

- IAM
- SIEM
- Phishing tool
- Critical Infrastructure Protection (CIP) Version 5 audit by NPCC (occurs every 3 years)

IT INFRASTRUCTURE ENHANCEMENTS

- Control Room Wallboard
- Storage and Network Devices

nGEM DAY-AHEAD MARKET CLEARING ENGINE IMPLEMENTATION



Q1 2021 | Q2 2021 | Q3 2021 | Q4 2021

Markets Related

- Energy-Security Improvements
- New England's Future Grid Initiative
- Submission of FTRs for Clearing
- Peak-Hour Assessments

Operations/ Planning

- Transmission Planning for the Evolving Grid
- Order 1000 Lessons Learned
- 2021 Regional System Plan
- Peak-Hour Assessments
- Forecasting Enhancements
- Continuing Business

Capital Project Priorities

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

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Paul Belval and Patrick Gerity, NEPOOL Counsel

DATE: September 24, 2020

RE: ISO New England Inc. ("ISO") 2021 Operating and Capital Budgets
New England States Committee on Electricity ("NESCOE") 2021 Budget

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At its October 1, 2020 meeting, the Participants Committee (the "NPC") will be asked to vote on the ISO's proposed 2021 operating and capital budgets (collectively, the "ISO Budgets") and on NESCOE's 2021 operating budget (the "NESCOE Budget"). We have included with this memorandum background materials regarding these budgets.

The ISO 2021 Budgets

The ISO Budgets were presented and reviewed in accordance with the processes included in the Participants Agreement and in the Settlement Agreement with state agencies in FERC Dockets Nos. ER13-185 and ER13-192. The 2021 ISO operating budget, prior to true-ups, reflects a 1.6 percent increase over the 2020 operating budget. After accounting for the true-up mechanism in the ISO Tariff, the revenue requirement to fund the 2021 operating budget (i.e., the amount collected under the ISO administrative cost tariff) will increase by 3.2 percent over the amount projected to be collected in 2020. The ISO capital budget for 2021 is $28 million. This reflects no change from the amounts of the 2018, 2019 or 2020 capital budgets.

The ISO presented its preliminary budgets to NECPUC in early June and to NEPOOL at the virtual summer NPC meeting. The ISO next presented the ISO Budgets to the NEPOOL Budget & Finance Subcommittee (the "Subcommittee") and to the New England state agencies and attorneys general in separate meetings on August 10. The ISO's Chief Financial Officer, Mr. Robert Ludlow also provided a written overview of the ISO Budgets with the materials for the September 3 NPC meeting, gave a high-level summary of the ISO Budgets and offered to answer any questions that NPC members have on the ISO Budgets. Questions on the ISO Budgets provided by certain New England state regulators and consumer advocates, as well as the ISO's responses thereto, are posted on the ISO's website and were included with the materials circulated and posted for the September 3 NPC meeting.

Included with this memorandum is a memorandum from Mr. Ludlow describing the changes that have been made to the ISO Budgets from the versions reviewed by the Subcommittee and provided previously to the NPC. That memorandum includes a link to the updated ISO Budgets presentation[1] and

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[1] https://www.iso-ne.com/static-assets/documents/2020/09/07_isone_proposed_2021_op_ca_budget_updated_09_23_2020.pdf

a link to the comments from the New England state regulators and consumer advocates and the ISO's response to those comments.[2] The ISO's September 21 memorandum regarding the allocation of its projected costs among the ISO Tariff Schedules is also included with this memorandum.[3]

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

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

The NESCOE 2021 Budget

Ms. Heather Hunt, the Executive Director of NESCOE, joined the Subcommittee's August 10 meeting and informed the Subcommittee that NESCOE expected the NESCOE Budget for 2021 to be approximately $2,428,300, slightly less than the $2,541,400 included in the five-year *pro forma* projections supported by the NPC in June 2017 and accepted by the FERC. That fact was reported at the last NPC meeting as well. A summary presentation regarding the NESCOE Budget, which reflects 2021 Schedule 5 Rate under the ISO Tariff as calculated by the ISO ($0.00626 per kW-mo.) is included with this memorandum and will be posted with composite materials for this meeting. The NESCOE Budget presentation dated September 24, 2020 is identical to the NESCOE August 10, 2020 presentation, with only slide 12 updated to reflect the final 2021 Network Load factor and final Schedule 5 Rate.

The following form of resolution can be used by the NPC in its consideration of the proposed 2021 NESCOE Budget:

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

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

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[2] https://www.iso-ne.com/static-assets/documents/2020/09/07_states_2021_budget_comments_isone_response.pdf

[3] The memo addressing the Projected 2021 Revenue Requirement, including the final true-up for 2019 and a comparison to the 2020 Revenue Requirement, a Draft 2021 Revenue Requirement by activity, and Draft 2021 Rate Components, was circulated by the ISO to Participants Committee members and alternates and Budget & Finance Subcommittee members on September 21.

ISO new england

memo

To: NEPOOL Participants Committee

From: Robert C. Ludlow, VP & CFO

Date: September 23, 2020

Subject: ISO New England's 2021 Proposed Operating and Capital Budgets

This 2021 operating and capital budgets (the "Budgets") update is intended to provide the NEPOOL Participants Committee with information regarding the changes that have been made to the ISO's 2021 proposed Budgets since the last review of the Budgets at the September 3, 2020 NEPOOL Participants Committee ("NPC") meeting.

Summary of Changes

The 2021 operating budget remains unchanged from the version presented to the NEPOOL Budget and Finance Subcommittee in August and to the NPC in September. There is an update to slide 52 to reflect updated compensation survey data that has been received since the August meeting. In summary, the 2021 operating budget, excluding the true-up, is an increase of 1.6% or $3.2M as compared to the 2020 operating budget. The 2021 operating budget, including the true-up, results in a 3.2% increase to the Revenue Requirement compared to 2020.

The 2021 overall capital budget of $28.0M has not changed. Although the total budget for 2021 remains the same, there were changes to the following capital projects: the nGEM Market Clearing Engine Implementation project has moved from the planning phase to chartered and had a slight change in the 2021 budget amount and the overall project budget; there is a reallocation of costs from 2020 to 2021 for the Forward Capacity Tracking System Infrastructure Conversion Part II, although no change to the overall project budget; and the 2021 Other Emerging Work balance was adjusted to reflect the funding changes to the foregoing projects. In addition, adjustments were made to the 2020 budget amounts and the overall project budgets for following: Energy Security Improvements, CIP Electronic Security Perimeter Redesign, Human Resources Workflow & Document Management, and TranSMART Technical Architecture Update.

Materials

The August 10, 2020 budget presentation (the "Budget Presentation") presented to the NEPOOL Budget and Finance Subcommittee has been updated to reflect the changes described above. The updated Budget Presentation can be found at the following link: https://www.iso-ne.com/static-assets/documents/2020/09/07_isone_proposed_2021_op_ca_budget_updated_09_23_2020.pdf

The 2021 state agencies' written comments and the accompanying response can be found at the following link: https://www.iso-ne.com/static-assets/documents/2020/09/07_states_2021_budget_comments_isone_response.pdf

Budget Presentation Slide Changes

The following pages have been updated in the Budget Presentation:

Operating Budget Compensation Slide, page 52

Capital Budget Slides, pages: 26, 27, 101, 103, 106, 123, 125, and 126

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

memo

To: NEPOOL Budget & Finance Subcommittee and Participants Committee

From: Bob Ludlow and Cheryl Arnold

Date: September 21, 2020

Subject: Projected 2021 Revenue Requirement for ISO New England Administrative Cost Tariff Schedules

To help our Participants prepare their 2021 budgets and consistent with information provided in previous years, this memo includes a preliminary indication of ISO-NE's 2021 costs and related tariff schedules. Specifically, the memo includes (1) the estimated 2021 Revenue Requirement, including the final true-up for 2019 and a comparison to the 2020 Revenue Requirement (see Exhibit 1 below), (2) the Draft 2021 Revenue Requirement by activity (see Exhibit 2), and (3) the Draft 2021 Rate Components (see Exhibit 3). Both Exhibits 2 and 3 are attached and, in their final form, will be part of the ISO's budget filing with the FERC. The cost assignment and allocation mechanisms that were utilized in the Draft 2021 tariff schedules were established as part of the settlement that has been in effect for the last nineteen years.

Overall Change in Revenue Requirement

As shown in Exhibit 1 below, the overall Revenue Requirement has increased by $6.3 million year-over-year, from $198.8M for 2020 to $205.1M for 2021.[1] The change includes a $3.2 million increase in the revenue requirement before taking into account the change in prior year true-ups. Prior year true-ups resulted in an increase of $3.1M. The 2020 tariff included a $2.9M revenue requirement decrease for the final 2018 true-up, while the 2021 tariff will include an increase of $0.2M as a result of the final 2019 true-up.

Draft Exhibit 1

ISO New England
Revenue Requirement By Tariff Schedule
2021 Estimated Amount vs. 2020 Filed Amount

	Sch 1	**Sch 2**	**Sch 3**	**Total**
2021 Revenue Requirement Before Prior Year True Ups	$ 43,558,799	$ 99,301,285	$ 62,103,185	$ 204,963,269
2020 Revenue Requirement Before Prior Year True Ups	41,697,171	95,982,740	64,056,782	201,736,693
$ Increase/(Decrease) from 2020 to 2021	**1,861,627**	**3,318,546**	**(1,953,597)**	**3,226,576**
% Increase/(Decrease) from 2020 to 2021	**4.5%**	**3.5%**	**(3.0%)**	**1.6%**
2021 Revenue Requirement Prior Year True Ups-Under/(Over) Collect	$ (1,447,780)	$ 759,504	$ 839,312	$ 151,036
2020 Revenue Requirement Prior Year True Ups-Under/(Over) Collect	(1,615,547)	(1,398,827)	64,929	(2,949,445)
$ Increase/(Decrease) from 2020 to 2021	**167,767**	**2,158,331**	**774,383**	**3,100,481**
2021 Revenue Requirement Including Prior Year True-Ups	$ 42,111,019	$ 100,060,789	$ 62,942,497	$ 205,114,305
2020 Revenue Requirement Including Prior Year True-Ups	40,081,624	94,583,913	64,121,711	198,787,248
$ Increase/(Decrease) from 2020 to 2021	**2,029,394**	**5,476,877**	**(1,179,214)**	**6,327,057**
% Increase/(Decrease) from 2020 to 2021	**5.1%**	**5.8%**	**(1.8%)**	**3.2%**

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[1] Minor variances may appear due to rounding among the various presentations and schedules for the 2021 Budgets.

Change in Revenue Requirement by Schedule

Before true-ups in 2021 and 2020, the 2021 Revenue Requirement reflects an overall increase of $3.2M or 1.6% over the 2020 Revenue Requirement. By tariff schedule, the changes are: Schedule 1, a $1.9M or 4.5% *increase*; Schedule 2, a $3.3M or 3.5% *increase*; and Schedule 3, a $2.0M or 3.0% *decrease*.

The Tariff Schedule 1 increase of $1.9M is attributable to:

- Increases that impact all three schedules, including for compensation and employee benefit costs, computer services and systems support, and cyber security and NERC CIP compliance.
- An increase in depreciation expense as a result of the Energy Management Platform 3.2 Upgrade Parts I and II projects that are more heavily weighted towards Schedules 1 and 2.
- Depreciation changes that impact all three schedules, including both increases and decreases that largely offset. Increases include those for the Enterprise Application Integration Replacement Phase I, Change Request System Replacement, and Application Server Upgrade projects. Decreases for projects that will be fully depreciated by 2021 and reducing costs are the Situational Awareness – Video Wall Expansion Phases I and II projects.

The Tariff Schedule 2 increase of $3.3M is attributable to:

- Funding for items that impact all three schedules, as noted above in the explanation for Schedule 1.
- Depreciation expense for Schedule 2 had a small net increase due to the CIMNET Simultaneous Feasibility Test with Data Transfer Enhancements project that is allocated entirely to Schedule 2 and, as noted above, the Energy Management Platform 3.2 Upgrade Parts I and II projects that are more heavily weighted towards Schedules 1 and 2. Offsetting the depreciation increases are reductions for the Sub-Hourly Settlements and Internal Market Monitoring Data Analysis Phase I projects that will be fully depreciated by mid-2021 and that are allocated entirely to Schedule 2.

The Tariff Schedule 3 decrease of $2.0M includes:

- Reductions for FERC Order 1000 competitive transmission solution proposal work, the reevaluation and updating of Cost of New Entry (CONE), Net CONE, and Offer Review Trigger Price in the Forward Capacity Market, and lower dues for the Northeast Power Coordinating Council.
- A decrease in depreciation expense due to the Forward Capacity Market (FCM) – Pay for Performance and FCM Improvements projects that will both be fully depreciated by mid-2021 and are allocated entirely to Schedule 3.
- Partially offsetting the Schedule 3 reductions is funding for items that impact all three schedules, as noted above in the explanation for Schedule 1.

The ISO 2021 Revenue Requirement will be reviewed and voted on at the October 1, 2020 NPC meeting. Should you have any questions regarding the information provided in this memo, do not hesitate to contact us.

Exhibit 2
Page 1 of 6

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Line	Activity Code		Allocation	Self-Funding Tariff			
No.	No.	Description	Factor (1)	Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**Administration-CEO**					
2	12651	Indirect Administrative Support	Total Dir Labor	$ 8,893,243	$ 1,916,494	$ 4,602,253	$ 2,374,496
3	12652	NEPOOL Committee Support	Total Dir Labor	7,926	1,708	4,102	2,116
4	12654	National Committee Support	Total Dir Labor	1,080	233	559	288
5	12657	Indirect Administrative Support for BCC	Total Dir Labor	799,747	172,345	413,869	213,532
6		Total		9,701,996	2,090,780	5,020,783	2,590,433
7							
8		**Finance**					
9	11601	Payroll Administration	Total Dir Labor	552,653	119,097	285,998	147,558
10	11701	Accounts Payable	Total Dir Labor	163,087	35,145	84,397	43,544
11	11702	Procurement	Total Dir Labor	452,464	97,506	234,150	120,808
12	11901	Settle for Power Transactions	Total Dir Labor	162,269	34,969	83,974	43,326
13	12001	Budgeting and Forecasting	Total Dir Labor	718,646	154,868	371,899	191,878
14	12005	Credit Administration	Total Dir Labor	426,660	91,945	220,797	113,918
15	12017	Forward Capacity Market (FCM) Reforms	Total Dir Labor	30,030	-	-	30,030
16	12101	Ledger Closing, Financial Statements and Tax Reporting	Total Dir Labor	405,672	87,422	209,935	108,314
17	12201	Treasury and Cash Management	Total Dir Labor	2,115,469	455,884	1,094,755	564,830
18	92004	Depreciation Expense 2004 Assets	Alloc-Fixed	43,160	8,988	22,535	11,637
19	92005	Depreciation Expense 2005 Assets	Alloc-Fixed	773,169	163,467	402,126	207,577
20	92006	Depreciation Expense 2006 Assets	Total Dir Labor	568,947	122,608	294,430	151,909
21	92007	Depreciation Expense 2007 Assets	Total Dir Labor	157,621	33,967	81,569	42,085
22	92008	Depreciation Expense 2008 Assets	Total Dir Labor	2,677	577	1,385	715
23	92009	Depreciation Expense 2009 Assets	Total Dir Labor	1,535	331	794	410
24	92010	Depreciation Expense 2010 Assets	Total Dir Labor	2,380	513	1,232	635
25	92011	Depreciation Expense 2011 Assets	Total Dir Labor	249	54	129	66
26	92012	Depreciation Expense 2012 Assets	Total Dir Labor	88,304	19,030	45,697	23,577
27	92013	Depreciation Expense 2013 Assets	Total Dir Labor	984,508	212,161	509,483	262,864
28	92014	Depreciation Expense 2014 Assets	Alloc-Fixed	251,390	53,816	130,897	66,677
29	92015	Depreciation Expense 2015 Assets	Alloc-Fixed	38,935	8,390	20,149	10,396
30	92016	Depreciation Expense 2016 Assets	Alloc-Fixed	377,664	51,028	220,793	105,844
31	92017	Depreciation Expense 2017 Assets	Alloc-Fixed	2,207,241	220,747	1,107,107	879,387
32	92018	Depreciation Expense 2018 Assets	Alloc-Fixed	5,703,461	695,848	2,900,538	2,107,075
33	92019	Depreciation Expense 2019 Assets	Alloc-Fixed	7,801,094	1,342,628	4,165,193	2,293,273
34	92020	Depreciation Expense 2020 Assets	Alloc-Fixed	6,182,334	1,018,646	3,515,279	1,648,409
35	92021	Depreciation Expense 2021 Assets	Alloc-Fixed	1,056,951	229,585	502,087	325,280
36	99707	Amortization of Land Recovery	Alloc-Fixed	39,300	2,460	24,170	12,670
37	99995	NPCC/NERC Dues	Alloc-Fixed	6,140,054	-	-	6,140,054
38	99996	Operating Contingency	Total Dir Labor	700,000	150,850	362,250	186,900
39	99996	Operating Contingency	Total Dir Labor	1,100,000	237,050	569,250	293,700
40	99998	Payroll & Other Accruals	Total Dir Labor	13,025,247	2,806,941	6,740,565	3,477,741
41		Total		52,273,170	8,456,520	24,203,564	19,613,086
42							
43		**Facilities & Security**					
44	12664	Building Maintenance	Total Dir Labor	3,435,135	740,272	1,777,682	917,181
45		Total		3,435,135	740,272	1,777,682	917,181
46							
47		**Enterprise Risk Management**					
48	22704	Record Retention Services	Alloc-Fixed	58,483	19,475	19,475	19,533
49	22705	Corporate Scorecard	Alloc-Fixed	45,497	15,151	15,151	15,196
50	22706	Document Management Services	Alloc-Fixed	100,094	40,038	30,028	30,028
51	22708	ERM Adminstration	Total Dir Labor	3,024	652	1,565	807
52	22709	Management	Total Dir Labor	126,632	27,289	65,532	33,811
53	22710	Employee Development	Total Dir Labor	27,298	5,883	14,127	7,289
54	22714	Analysis	Total Dir Labor	426,307	91,869	220,614	113,824
55	22721	Corp Strategic Risk	Total Dir Labor	405,672	87,422	209,935	108,314
56	22727	ERM Business Analysis	Total Dir Labor	185,398	39,953	95,943	49,501
57	23006	Business Continuity Planning	Total Dir Labor	113,144	24,382	58,552	30,209
58	25011	Corrective Action/Preventive Action	Alloc-Fixed	115,170	38,352	38,352	38,467
59	25014	EtQ Tools Dev & Support	Total Dir Labor	66,287	14,285	34,303	17,699
60		Total		1,673,005	404,750	803,576	464,678
61							
62		**Human Resources**					
63	12661	Employee Affairs (Recreation Committee)	Total Dir Labor	47,118	10,154	24,384	12,581
64	12701	Recruiting/Interviewing	Total Dir Labor	682,222	147,019	353,050	182,153
65	12702	Intern Expense	Total Dir Labor	140,189	30,211	72,548	37,431
66	12801	Employee Relations	Total Dir Labor	60,456	13,028	31,286	16,142
67	12901	Benefit Administration	Total Dir Labor	1,419,333	305,866	734,505	378,962
68	12951	Compensation	Total Dir Labor	489,711	105,533	253,425	130,753
69	12961	HR - General	Total Dir Labor	1,307,456	281,757	676,608	349,091
70	12962	HR - Training	Total Dir Labor	1,211,186	261,011	626,789	323,387
71	13410	Power Training & Development	Total Dir Labor	494,404	106,544	255,854	132,006
72	13411	Markets Training & Development	Total Dir Labor	63,750	13,738	32,991	17,021
73	13412	People Training & Development	Total Dir Labor	156,079	33,635	80,771	41,673
74	13413	Business Skills Training & Development	Total Dir Labor	290,896	62,688	150,539	77,669
75	13414	Technology Training & Development	Total Dir Labor	950,795	204,896	492,037	253,862
76	13901	Performance Eval/Salary Review	Total Dir Labor	73,776	15,899	38,179	19,698
77		Total		7,387,372	1,591,979	3,822,965	1,972,428

Exhibit 2
Page 2 of 6

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Line	Activity Code		Allocation	Self-Funding Tariff			
No.	No.	Description	Factor (1)	Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**Legal Department**					
2	12422	Interconnection Queue	Alloc-Fixed	103,902	-	-	103,902
3	12502	Board of Directors	Total Dir Labor	169,054	36,431	87,485	45,137
4	12508	Energy Markets / Complaints / Rule Changes	Alloc-Fixed	1,769,318	-	1,769,318	-
5	12513	Miscellaneous Labor Matters	Total Dir Labor	120,000	25,860	62,100	32,040
6	12514	NEPOOL Participants Committee	Total Dir Labor	147,601	31,808	76,383	39,409
7	12517	Administrative and Clerical Support	Total Dir Labor	536,828	115,686	277,809	143,333
8	12543	Independent Market Advisor	Alloc-Fixed	1,100,000	-	770,000	330,000
9	12559	General Corporate	Total Dir Labor	1,588,683	342,361	822,143	424,178
10	12584	Installed Capacity Requirements	Total Dir Labor	51,951	-	-	51,951
11	12587	Capacity Market Development	Alloc-Fixed	387,102	-	-	387,102
12	12588	Web Content Management	Total Dir Labor	709,341	152,863	367,084	189,394
13	12619	Compliance	Alloc-Fixed	138,536	55,415	55,415	27,707
14	12622	Open Access Transmission Tariff	Alloc-Fixed	51,951	51,951	-	-
15	12623	Reliability Standards	Alloc-Fixed	51,951	-	10,390	41,561
16	12631	FERC Order 1000 (Legal Only)	Alloc-Fixed	173,170	-	-	173,170
17	12663	Public Information	Total Dir Labor	1,726,779	372,121	893,608	461,050
18	12669	Government Affairs	Total Dir Labor	1,802,162	388,366	932,619	481,177
19		Total		10,628,331	1,572,862	6,124,355	2,931,114
20							
21		**Internal Audit**					
22	15001	Indirect Management Duties	Total Dir Labor	114,213	24,613	59,105	30,495
23	15002	Personnel Management	Total Dir Labor	23,099	4,978	11,954	6,167
24	15003	Budget & Forecasting	Total Dir Labor	23,099	4,978	11,954	6,167
25	15004	Audit Follow-up Activities	Total Dir Labor	80,846	17,422	41,838	21,586
26	15005	Audit & Finance Committee	Total Dir Labor	72,013	15,519	37,267	19,228
27	15006	Internal Audit Business Process Update	Total Dir Labor	11,549	2,489	5,977	3,084
28	15007	Annual Audit Work Plan	Total Dir Labor	60,464	13,030	31,290	16,144
29	15011	Internal Audit Meetings	Total Dir Labor	34,648	7,467	17,930	9,251
30	15013	Indirect Adminstrative Support	Total Dir Labor	48,914	10,541	25,313	13,060
31	15021	Performance Measurements	Total Dir Labor	23,099	4,978	11,954	6,167
32	15022	Vendor Contracts	Total Dir Labor	11,549	2,489	5,977	3,084
33	15023	Wire Transfers	Total Dir Labor	11,549	2,489	5,977	3,084
34	15029	Payroll	Total Dir Labor	34,648	7,467	17,930	9,251
35	15031	Employee Expense Reporting	Total Dir Labor	11,549	2,489	5,977	3,084
36	15040	Operations	Total Dir Labor	150,142	32,356	77,699	40,088
37	15085	Information Technology	Total Dir Labor	316,938	68,300	164,016	84,623
38	15107	Active Directory Security Admin and Change/Config Mgmt Audit	Total Dir Labor	97,500	21,011	50,456	26,033
39	15110	Systems Development Reviews	Total Dir Labor	69,296	14,933	35,861	18,502
40	15133	Satellite Operations Reviews	Total Dir Labor	35,492	7,649	18,367	9,476
41	15137	Satellite IT Reviews	Total Dir Labor	844	182	437	225
42	15161	External Audit- Pension Audit	Total Dir Labor	113,452	24,449	58,712	30,292
43	15162	External Audit- Financial Audit	Total Dir Labor	129,536	27,915	67,035	34,586
44	15166	External Audit -Pricing Module Certification	Alloc-Fixed	10,120	-	10,120	-
45	15176	External Audit - ISO Internet Vulnerability Assessment	Total Dir Labor	14,168	3,053	7,332	3,783
46	15186	External Audit - SSAE 18 Direct Support	Total Dir Labor	23,099	4,978	11,953	6,167
47	25702	External Audit - SSAE 18 Direct Management	Alloc-Fixed	480,697	-	480,697	-
48	28005	Fraud, Waste & Abuse Program	Total Dir Labor	63,549	13,695	32,887	16,968
49	28007	Contractor/Consultant Review	Total Dir Labor	13,000	2,802	6,728	3,471
50	28173	Identity and Access Management Audit	Alloc-Fixed	26,000	7,800	7,800	10,400
51	28176	CIP Oversight, Monitoring, and Reporting Processes Review	Total Dir Labor	96,747	20,849	50,067	25,831
52	28178	Third Party Cyber Risk Management Process Review	Total Dir Labor	34,648	7,467	17,930	9,251
53	28179	NERC CIP V5.0 Mock Audit	Total Dir Labor	23,099	4,978	11,954	6,167
54		Total		2,259,569	383,363	1,400,491	475,715
55							
56		**COO-Adm**					
57	19001	NEPOOL Committee Support	Total OPS Labor	121,798	32,642	58,402	30,754
58	19002	Regional Committee Support	Total OPS Labor	2,520	675	1,208	636
59	19003	National Committee Support	Total OPS Labor	35,221	9,439	16,888	8,893
60	19005	Indirect Supervision/Clerical Support	Total OPS Labor	2,132,274	571,449	1,022,425	538,399
61	19009	Renewable Resource Integration	Alloc-Fixed	144,143	-	-	144,143
62		Total		2,435,956	614,206	1,098,924	722,826
63							
64		**System Operations & Market Administration**					
65	14404	NEPOOL Committee Support	SOA Labor	1,250	432	580	238
66	14405	Indirect Supervision/Clerical Support	SOA Labor	130,331	45,016	60,500	24,815
67	14407	Regional Committee Support	SOA Labor	1,250	432	580	238
68	14408	National Committee Support	SOA Labor	78,633	27,160	36,501	14,972
69	19101	NEPOOL Committee Support	MOA Labor	34,999	-	24,499	10,500
70		Total		246,463	73,040	122,661	50,762

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Line	Activity Code		Allocation	Self-Funding Tariff			
No.	No.	Description	Factor (1)	Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**Operations**					
2	14001	Generation Dispatch	Alloc-Fixed	3,361,230	-	2,823,433	537,797
3	14002	Transmission Operations	Alloc-Fixed	3,361,230	2,688,984	168,061	504,184
4	14304	Advanced Scheduling and Forecasting	Alloc-Fixed	2,319,299	115,965	1,832,246	371,088
5	14402	Operations Training	Alloc-Fixed	3,321,003	1,328,401	1,328,401	664,201
6	14413	Operations Support Training & Development	Alloc-Fixed	135,000	54,000	54,000	27,000
7	14563	National Committee Support	OPS Labor	17,109	4,784	9,471	2,854
8	14564	Indirect Supervision/Clerical Support	OPS Labor	1,332,694	372,621	737,780	222,293
9	14565	Employee Development	OPS Labor	49,648	13,882	27,485	8,281
10	14581	Application Testing and Development	Total Dir Labor	60,456	13,028	31,286	16,142
11	14702	Procedure Documentation	Alloc-Fixed	130,234	52,093	52,093	26,047
12		Total		14,087,901	4,643,758	7,064,257	2,379,886
13							
14		**Reliability and Operations Compliance**					
15	14803	Regional Committee Support	OS Labor	75,270	37,635	-	37,635
16	14804	National Committee Support	OS Labor	139,946	69,973	-	69,973
17	14806	Employee Development	Alloc-Fixed	47,358	26,307	9,154	11,896
18	14807	NERC RSAW Update and Audit Prep	Alloc-Fixed	59,197	29,599	-	29,599
19	14808	Change Management	Alloc-Fixed	23,679	10,655	2,368	10,655
20	14809	Tariff Compliance	Alloc-Fixed	177,591	53,277	106,555	17,759
21	14810	NERC Self Certifications	Alloc-Fixed	59,197	50,318	-	8,880
22	14812	NPCC MP Referral	Alloc-Fixed	59,197	23,679	23,679	11,839
23	14815	Identifications and Description of Internal Controls	Total Dir Labor	317,923	68,512	164,525	84,885
24	14816	Support NE Compliance Groups	Total Dir Labor	118,394	25,514	61,269	31,611
25	14817	AskISO Customer or Internal Inquiries	Total Dir Labor	118,394	25,514	61,269	31,611
26		Total		1,196,146	420,983	428,819	346,344
27							
28		**Operations Support Services**					
29	14301	Contract Administration and Scheduling	Alloc-Fixed	(60,000)	(6,000)	(42,000)	(12,000)
30	14453	National Committee Support	TSO Labor	18,360	5,943	8,778	3,639
31	14454	Indirect Supervision/Clerical Support	TSO Labor	3,501	1,133	1,674	694
32	14467	Nuclear Plant Liaison	Alloc-Fixed	17,109	-	-	17,109
33	14477	Participant project and outage coordination support	Alloc-Fixed	17,109	8,554	-	8,554
34	14765	GRIDEX - Grid Exercise	Alloc-Fixed	53,543	26,771	-	26,771
35	18361	Transmission Studies, Operations, OASIS Support	Alloc-Fixed	3,381,914	2,705,531	169,096	507,287
36	18381	Transmission Outage Application - Short Term	Alloc-Fixed	1,515,610	1,212,488	75,780	227,341
37	18382	Transmission Outage Application - Long Term	Alloc-Fixed	1,515,610	-	-	1,515,610
38		Total		6,462,755	3,954,421	213,328	2,295,006
39							
40		**Market Monitoring**					
41	16101	Market Power Monitoring and Mitigation	Alloc-Fixed	3,928,665	-	2,750,066	1,178,600
42	16102	Regulatory Activities	Alloc-Fixed	5,760	-	4,032	1,728
43	16115	Analysis & Internal Reports	Alloc-Fixed	325,883	-	228,118	97,765
44	16121	FCM Market Monitoring	Alloc-Fixed	816,649	-	-	816,649
45		Total		5,076,957	-	2,982,216	2,094,741
46							
47		**Market & Resource Administration**					
48	21901	Day Ahead Market Administration	Alloc-Fixed	641,603	-	641,603	-
49	21902	Real Time Price Verification	Alloc-Fixed	604,408	-	604,408	-
50	21904	NEPOOL Committee Support	MA Labor	18,981	-	18,381	600
51	21907	Indirect Supervision/Clerical Support	MA Labor	112,319	-	108,770	3,549
52	21908	Employee Development	MA Labor	104,617	-	101,311	3,306
53	21909	Customer Support	MA Labor	37,313	-	36,134	1,179
54	21913	Data Collection/Report Writing	Alloc-Fixed	185,972	-	185,972	-
55	21915	FTR/Auction Administration	Alloc-Fixed	316,152	158,076	158,076	-
56	21916	Forward Reserve Market - Administration	Alloc-Fixed	74,389	-	-	74,389
57	21917	Real Time Price Finalization	Alloc-Fixed	223,166	-	223,166	-
58	21951	FCM Annual Reconfiguration Auction Administration	Alloc-Fixed	18,597	-	-	18,597
59	21953	FCM Monthly Administration	Alloc-Fixed	37,194	-	-	37,194
60		Total		2,374,711	158,076	2,077,821	138,814

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Line	Activity Code		Allocation	Self-Funding Tariff			
No.	No.	Description	Factor (1)	Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**Market Analysis & Settlements**					
2	1701	Billing Statements - Energy	Alloc-Fixed	120,876	-	120,876	-
3	1702	Billing Statements - Transmission	Alloc-Fixed	169,226	169,226	-	-
4	1713	Billing Statements - ISO Tariff	Total Dir Labor	24,175	5,210	12,511	6,455
5	2047	Score Card	STLM Labor	7,253	1,073	3,533	2,647
6	2048	FCM	Alloc-Fixed	396,971	-	-	396,971
7	2049	Product Testing	Alloc-Fixed	24,175	-	19,340	4,835
8	2051	Legal Support	Alloc-Fixed	24,175	-	12,088	12,088
9	2005	Customer Service	STLM Labor	145,051	21,453	70,654	52,944
10	2007	Admin support - NEPOOL Committees	STLM Labor	18,703	2,766	9,110	6,826
11	2009	Indirect Supervision/Clerical Support	STLM Labor	842,337	124,582	410,302	307,453
12	2010	Employee Development	STLM Labor	193,401	28,604	94,206	70,591
13	2013	FTR Administration	Alloc-Fixed	36,263	-	36,263	-
14	2014	Billing Statements - NCPC	Alloc-Fixed	199,444	-	99,722	99,722
15	2020	Billing Disputes	Total Dir Labor	24,175	5,210	12,511	6,455
16	2024	ASM Regulation	Alloc-Fixed	24,175	-	-	24,175
17	2025	ASM Locational Forward Reserve	Alloc-Fixed	96,701	-	-	96,701
18	2032	Billing	STLM Labor	48,350	7,151	23,551	17,648
19		Total		2,395,451	365,274	924,666	1,105,510
20							
21		**Market Operations Support Services**					
22	3000	Hourly Settlements Support	Alloc-Fixed	334,763	-	167,381	167,381
23	3002	Monthly Settlements Support	Alloc-Fixed	186,588	93,294	-	93,294
24	3003	Market Analysis Support	Alloc-Fixed	223,175	-	223,175	-
25	3006	Customer Service	Alloc-Fixed	44,635	-	44,635	-
26	3008	Admin Support	Alloc-Fixed	714,719	-	714,719	-
27	3009	Indirect Supervision (Principal Analysts only)	Alloc-Fixed	418,454	-	418,454	-
28	3010	Employee Development	Alloc-Fixed	86,369	-	86,369	-
29	3012	FERC Data Request	Alloc-Fixed	16,515	-	16,515	-
30	3016	Market Monitoring Assistance	Alloc-Fixed	893	-	893	-
31	3017	Project MAS (Market Analysis & Settlements)	Alloc-Fixed	136,588	34,147	34,147	68,294
32	3018	Project MRA (Market and Resource Administration)	Alloc-Fixed	69,631	-	69,631	-
33		Total		2,232,328	127,441	1,775,918	328,969
34							
35		**Market Services**					
36	16001	Participant/membership support	Alloc-Fixed	9,732	-	4,866	4,866
37	16006	Call Support (Ask ISO)	Alloc-Fixed	1,321,385	343,560	872,114	105,711
38	16414	Direct Customer Contact	MS Labor	39,983	-	35,984	3,998
39	16419	Asset Registration Implemented	Alloc-Fixed	446,332	-	446,332	-
40	16420	Asset Registration Review	Alloc-Fixed	18,597	-	18,597	-
41	16422	Claimed Capability Audits	Alloc-Fixed	446,332	-	446,332	-
42	16424	Demand Resource Audits	Alloc-Fixed	37,194	-	37,194	-
43	16425	DR Registration Implemented	Alloc-Fixed	37,194	-	37,194	-
44		Total		2,356,750	343,560	1,898,615	114,575
45							
46		**Participant Training Services**					
47	16021	Training Development	Alloc-Fixed	560,326	-	280,163	280,163
48	16024	Training Delivery	Alloc-Fixed	17,057	-	8,528	8,528
49	16432	New Generation Coordination and Registration	Alloc-Fixed	185,972	-	185,972	-
50	16434	QMS/CAPA Process and Procedure Updates	Total Dir Labor	185,972	40,077	96,240	49,654
51	16436	Mkt Trng/Cus Serv Indirect Supervision	Total Dir Labor	299,870	-	299,870	-
52		Total		1,249,196	40,077	870,773	338,346
53							
54		**Planning Services**					
55	14313	National Committee Support	PSR Labor	63,307	6,881	3,191	53,235
56	17101	Analysis	Alloc-Fixed	521,468	-	365,028	156,440
57	17131	Calculate Objective Capability	Alloc-Fixed	300,025	-	-	300,025
58	17251	Regional Bulk Power System Assessment	Alloc-Fixed	27,446	13,723	13,723	-
59	17331	NEPOOL Committee Support	PSR Labor	80,401	8,740	4,052	67,609
60	17361	Regional Committee Support	PSR Labor	27,446	2,983	1,383	23,079
61	17401	Indirect Supervisory Activities	PSR Labor	217,629	23,656	10,969	183,004
62	17403	TCA Application Review	Alloc-Fixed	76,528	-	-	76,528
63	17405	Energy Efficiency Forecast	Alloc-Fixed	135,292	-	-	135,292
64	17408	MA - Energy Efficiency Advisory Council	Total Dir Labor	785	169	406	210
65	17501	FCA - Evaluate Existing Resource De-list Bids	Alloc-Fixed	102,756	-	-	102,756
66	17502	FCA - Preliminary Review of Show of Interest Applications	Alloc-Fixed	25,509	-	-	25,509
67	17503	FCA - New Resource Qualification Support	Alloc-Fixed	928,509	-	-	928,509
68	17504	FCA - Perform Transmission / Topology Assessments	Alloc-Fixed	76,528	-	-	76,528
69	17505	FCA - Perform Existing Resource Qualification	Alloc-Fixed	76,528	-	-	76,528
70	17507	FCA - Auctions & Filings	Alloc-Fixed	1,172,904	-	-	1,172,904
71	17508	FCA - Annual Reconfiguration Auction Support/Reliability Reviews	Alloc-Fixed	76,528	-	-	76,528
72	18101	Develop Load Forecast	Alloc-Fixed	509,436	101,887	101,887	305,661
73	18121	Operations Forecast Support	Alloc-Fixed	82,337	16,467	16,467	49,402
74	18131	Other Load Forecasting Activities	Alloc-Fixed	19,742	3,948	3,948	11,845
75	18133	Solar Load Forecast Development	Alloc-Fixed	82,337	16,467	16,467	49,402
76		Total		4,603,439	194,923	537,522	3,870,994

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Line	Activity Code		Allocation	Self-Funding Tariff			
No.	No.	Description	Factor (1)	Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**System Planning**					
2	18150	Regional Transmission Expansion Plan	Alloc-Fixed	602,171	451,629	150,543	-
3	18148	NEPOOL Committee Support	Alloc-Fixed	22,016	-	22,016	-
4	18152	States Requests	Alloc-Fixed	39,813	19,906	9,953	9,953
5	18401	Regional Activities	Alloc-Fixed	98,709	98,709	-	-
6	18402	Transmission Planning/Economic Studies Initiative	Alloc-Fixed	826,003	-	413,001	413,001
7	18531	Indirect Supervision/Clerical Support	SP Labor	162,082	40,245	28,737	93,100
8	18562	Project Management	Alloc-Fixed	78,967	78,967	-	-
9		Total		1,829,762	689,457	624,251	516,055
10							
11		**Transmission Planning**					
12	14715	Non DOE Funded/Unallowable	Alloc-Fixed	107,008	-	-	107,008
13	18201	Transmission System Assessment	Alloc-Fixed	3,004,662	3,004,662	-	-
14	18301	NEPOOL Administrative Support - Schedule 1 Tariff	Alloc-Fixed	26,452	26,452	-	-
15	18333	General SIS/FS	Alloc-Fixed	961,059	961,059	-	-
16	18334	Indirect Supervision/Clerical Support	Alloc-Fixed	437,535	437,535	-	-
17	18335	Regulatory Activities - NPCC	Alloc-Fixed	249,105	249,105	-	-
18	18336	National Activities	Alloc-Fixed	89,578	89,578	-	-
19	18343	FERC Order 1000	Alloc-Fixed	71,483	-	-	71,483
20	18346	OATT and Oper. Agreement Dev., Adm. and Support	Alloc-Fixed	309,096	309,096	-	-
21		Total		5,255,979	5,077,488	-	178,491
22							
23		**Program Management**					
24	801	Program Management - Administration	Total Dir Labor	1,231,430	265,373	637,265	328,792
25	1661	ISO Program Management	Alloc-Fixed	337,187	-	236,031	101,156
26		Total		1,568,617	265,373	873,296	429,948
27							
28		**Business Architecture and Technology**					
29	21201	Business Architecture and Technology	Total Dir Labor	3,510,015	756,408	1,816,433	937,174
30	21203	Employee Development	Total Dir Labor	45,196	9,740	23,389	12,067
31		Total		3,555,211	766,148	1,839,822	949,241
32							
33		**Market Development & Settlements Admin.**					
34	16607	National Committee Support	Total Dir Labor	40,489	8,725	20,953	10,810
35	19104	Indirect Supervision/Clerical Support	MOA Labor	327,694	-	229,386	98,308
36	21001	Market Development	Alloc-Fixed	1,086,043	-	543,021	543,021
37	21002	Administration	Total Dir Labor	220,715	47,564	114,220	58,931
38	21003	Employee Development	Total Dir Labor	66,102	14,245	34,208	17,649
39	21007	Budget/Forecast Support	Total Dir Labor	141,137	30,415	73,039	37,684
40	21011	Capacity Market	Alloc-Fixed	37,600	-	-	37,600
41	22402	Working Group Meetings and Support	Alloc-Fixed	28,518	-	14,259	14,259
42	22656	Energy, Reserve, and Regulation Markets	Alloc-Fixed	166,910	-	125,183	41,728
43	22657	ORTP/CONE Updates	Alloc-Fixed	88,030	-	-	88,030
44	22660	Energy Security	Alloc-Fixed	3,501,216	-	1,750,608	1,750,608
45		Total		5,704,455	100,950	2,904,877	2,698,629
46							
47		**NEPOOL Relations**					
48	22602	NEPOOL Committee Meetings & Support	Alloc-Fixed	348,066	-	174,033	174,033
49	22606	Governing Documents	Alloc-Fixed	13,989	-	6,995	6,995
50	22607	NEPOOL Committee Administration	Total Dir Labor	926,610	199,684	479,521	247,405
51		Total		1,288,665	199,684	660,548	428,432
52							
53		**IT Management**					
54	6517	Employee Development - Hardware/Software	Total Dir Labor	84,941	18,305	43,957	22,679
55	6519	Indirect Supervision and Clerical Support	Total Dir Labor	3,799,499	818,792	1,966,240	1,014,466
56	6552	Security	Total Dir Labor	1,043,825	224,944	540,180	278,701
57	6556	Budget Preparation, Tracking & Forecast	Total Dir Labor	124,044	26,731	64,193	33,120
58	6557	Information Technology Committee	Total Dir Labor	19,553	4,214	10,119	5,221
59	6650	Standards Development	Total Dir Labor	55,270	11,911	28,602	14,757
60	6651	IT - Software Code Security Analysis	Total Dir Labor	34,416	7,417	17,810	9,189
61	22501	Change Management Support	Alloc-Fixed	200,320	90,144	90,144	20,032
62	22505	Administrative	Alloc-Fixed	277,311	94,286	91,513	91,513
63		Total		5,639,179	1,296,743	2,852,758	1,489,678
64							
65		**IT Infrastructure Support**					
66	6510	Desktop Support - Hardware	Total Dir Labor	756,623	163,052	391,552	202,018
67	6511	Desktop Support - Software	Total Dir Labor	809,249	174,393	418,786	216,070
68	6512	Host Computer - Hardware	Alloc-Fixed	2,520,189	-	1,890,142	630,047
69	6513	Host Computer - Software	Alloc-Fixed	4,595,722	-	3,446,792	1,148,931
70	6514	Networking - Hardware	Total Dir Labor	658,669	141,943	340,861	175,865
71	6516	Communications	Total Dir Labor	2,899,286	624,796	1,500,380	774,109
72	6602	Help Desk Support	Total Dir Labor	364,214	78,488	188,481	97,245
73	6615	Host Computer Monitoring	Alloc-Fixed	1,233,954	-	616,977	616,977
74	6616	Desktop Support	Total Dir Labor	447,168	96,365	231,409	119,394
75	6617	System Administration - Unix	Total Dir Labor	592,555	127,696	306,647	158,212
76	6618	System Administration - Windows	Total Dir Labor	1,051,041	226,499	543,914	280,628
77	6621	Network Support	Total Dir Labor	594,313	128,074	307,557	158,681
78	6622	CIP & Systems Compliance	Total Dir Labor	1,123,747	242,167	581,539	300,040
79	6623	Asset Management	Total Dir Labor	1,048,306	225,910	542,498	279,898
80	6624	Infrastructure Review & Planning	Total Dir Labor	197,503	42,562	102,208	52,733
81	6625	Infrastructure Patch & Vulnerability Mitigation	Total Dir Labor	92,398	19,912	47,816	24,670
82		Total		18,984,938	2,291,858	11,457,560	5,235,519

Exhibit 2

DRAFT

Line	Activity Code		Allocation	Self-Funding Tariff			
No.	No.	Description	Factor (1)	Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**IT Cyber Security**					
2	6540	Security Compliance and Reporting	Total Dir Labor	2,766,481	596,177	1,431,654	738,650
3	6540A	Controls Assessment	Total Dir Labor	44,995	9,696	23,285	12,014
4	6540B	Virus/Malware Reporting and Response	Total Dir Labor	8,247	1,777	4,268	2,202
5	6540D	Intrusion Monitoring and Response	Total Dir Labor	798,460	172,068	413,203	213,189
6	6540E	System Compliance Enhancement	Total Dir Labor	127,463	27,468	65,962	34,032
7	6541	Security SW Tools Program	Total Dir Labor	123,924	26,706	64,131	33,088
8	6543	Critical Infrastructure Protection WG (NERC)	Total Dir Labor	20,935	4,512	10,834	5,590
9	6544	Cyber Security Impact Assessment	Total Dir Labor	125,264	26,994	64,824	33,446
10	6546	IT Audit Support	Total Dir Labor	177,309	38,210	91,757	47,341
11	6547	Cyber Security Training	Total Dir Labor	21,149	4,558	10,945	5,647
12	6548	CIP Compliance & Monitoring	Total Dir Labor	114,573	24,690	59,291	30,591
13		Total		4,328,799	932,856	2,240,154	1,155,789
14							
15		**IT Database & Analytics**					
16	6571	DBA Support - MOPS	Total Dir Labor	2,881,603	620,986	1,491,230	769,388
17	6581	IT Bridge Support	Total Dir Labor	197,231	42,503	102,067	52,661
18	6591	Data Architect - MOPS	Total Dir Labor	362,573	78,135	187,632	96,807
19	6594	IT Data Analyst	Total Dir Labor	553,781	119,340	286,582	147,860
20	6595	IT WEB Application Support	Total Dir Labor	538,081	115,956	278,457	143,668
21	6596	IT Data Governance	Total Dir Labor	327,102	70,491	169,275	87,336
22	21706	Enterprise Software Support	Total Dir Labor	823,575	177,480	426,200	219,895
23	21801	Software Support - Settlements	Alloc-Fixed	585,076	-	468,061	117,015
24	21802	Software Support - Publishing	Alloc-Fixed	103,251	-	82,600	20,650
25	21803	Software Support - Finance	Alloc-Fixed	786,646	-	629,317	157,329
26	21804	Software Support - Mitigation	Alloc-Fixed	190,010	-	152,008	38,002
27	21805	Software Support - TSO	Total Dir Labor	381,120	82,131	197,230	101,759
28	21806	Software Support - Enterprise	Total Dir Labor	1,338,123	288,366	692,479	357,279
29	21807	Software Support - Planning	Alloc-Fixed	201,097	-	160,878	40,219
30	21808	Training Delivery to NON-IT	Alloc-Fixed	168,503	-	134,803	33,701
31	21811	Single Sign On Support	Alloc-Fixed	157,145	-	125,716	31,429
32	21812	GADS Support	Alloc-Fixed	69,078	-	55,263	13,816
33	21814	Manual Database Edit	Total Dir Labor	55,425	11,944	28,682	14,798
34	21816	CMS Support	Total Dir Labor	124,863	26,908	64,617	33,338
35	21818	Discoverer Support	Total Dir Labor	56,497	12,175	29,237	15,085
36	21820	Service Desk Support	Total Dir Labor	92,104	19,848	47,664	24,592
37	21822	Integration Review and Assessment	Alloc-Fixed	25,681	2,568	15,408	7,704
38	21824	FCTS Support	Alloc-Fixed	529,600	-	-	529,600
39	21825	eTariff Support	Alloc-Fixed	69,078	-	55,263	13,816
40	21830	Annual Software Maintenance for Enterpirse Wide Software	Total Dir Labor	92,105	19,849	47,664	24,592
41		Total		10,709,351	1,688,680	5,928,332	3,092,339
42							
43		**IT Energy Management Systems**					
44	21600	Indirect Supervision and Administration	Total Dir Labor	258,236	55,650	133,637	68,949
45	21601	Power System Modeling	Total Dir Labor	48,348	10,419	25,020	12,909
46	21603	EMS Power System Applications Support	Total Dir Labor	763,697	164,577	395,213	203,907
47	21604	Dispatcher Training Simulatory Support	Alloc-Fixed	2,181,592	1,745,273	436,318	-
48	21605	DAM FTR/ARR Support	Alloc-Fixed	1,732,912	346,582	1,039,747	346,582
49	21606	Real-time Market Support	Alloc-Fixed	2,412,608	482,522	1,447,565	482,522
50	21607	Forecast Support	Alloc-Fixed	297,687	59,537	178,612	59,537
51		Total		7,695,081	2,864,561	3,656,114	1,174,407
52							
53		**IT Enterprise Applications Development**					
54	6518	Employee Development - Software	Total Dir Labor	33,561	7,232	17,368	8,961
55	21701	IT Settlement Application Support	Alloc-Fixed	100,000	-	80,000	20,000
56	21707	Application Analysis and Conceptual Design	Alloc-Fixed	212,539	-	170,031	42,508
57	21708	Application Design Evaluation and Selection	Alloc-Fixed	207,649	-	166,119	41,530
58	21709	Technology Evaluation and Selection	Alloc-Fixed	782,315	-	625,852	156,463
59	21710	Indirect Supervision and Administration	Alloc-Fixed	770,763	-	616,610	154,153
60	21711	EWR and CAPA Analysis	Alloc-Fixed	277,114	-	221,691	55,423
61		Total		2,383,941	7,232	1,897,671	479,037
62							
63		**IT Power System Modeling Management**					
64	21650	Indirect Supervision and Administration	Total Dir Labor	101,026	21,771	52,281	26,974
65	21651	Power System Modeling	Alloc-Fixed	1,168,524	467,410	467,410	233,705
66	21652	System Application Support	Alloc-Fixed	235,005	94,002	94,002	47,001
67	21654	NX9 Administration	Alloc-Fixed	536,703	214,681	214,681	107,341
68	21655	ICCP Support	Alloc-Fixed	949,248	379,699	379,699	189,850
69	21656	Transmission Project Management	Alloc-Fixed	25,047	20,038	5,009	-
70	21657	Model On Demand Admin	Alloc-Fixed	849,452	-	-	849,452
71	21658	Model on Demand Case Requests	Alloc-Fixed	51,768	-	-	51,768
72	21659	Synchrophasor Applications	Alloc-Fixed	25,884	3,883	3,883	18,119
73		Total		3,942,658	1,201,483	1,216,965	1,524,209
74							
75							
76		**Total ISO**		$ 204,963,269	$ 43,558,799	$ 99,301,285	$ 62,103,185

Exhibit 3

Draft 2021 Rate Components (1)

Tariff Schedule (a)	Jan. 1, 2021 (b)
Schedule 1	
Network Load (per kW-hour)	$0.00027
Schedule 2	
TU Bids (Virtual Inc/Dec)	
Submitted	$0.00500
Cleared	$0.06000
FTR Bids	
Submitted	$3.06279
Cleared	$3.94539
TU's	
Block 1 - 1st 12,500	$0.66974
Block 2 - Next 27,000	$0.60885
Block 3 - Over 39,500	$0.54797
Volumetric	
Block 1 - 1st 250,000	$0.39121
Block 2 - Next 1,250,000	$0.35565
Block 3 - Over 1,500,000	$0.32008
Schedule 3	
R-T NCP Load Obligation	$0.25351
Export Rate	$0.51000

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

New England States Committee on Electricity

2021 Budget Presentation

NEPOOL Budget & Finance Subcommittee

Presented: August 10, 2020

Resubmitted September 24, 2020

only change on p.12 to reflect final 2021 Network Load factor

NESCOE

Background: Budget Review

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

- ✓ Proposed 2021 budget conforms to:
  1) Boundaries of previously reviewed 5-year pro forma (2018 - 2022) supported by NEPOOL in June 2017 & accepted by FERC in August 2017
  2) NESCOE commitment not to seek an increase over pro forma budget of more than 10% in any 1 year - 2021 proposed budget is less than 2021 5-year pro forma budget
- ✓ Following calendar year 2019, independent auditor concluded NESCOE books conform to generally accepted accounting principles

Background: Policy Priorities

Term Sheet Provision Governing Identification of Policy Priorities

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

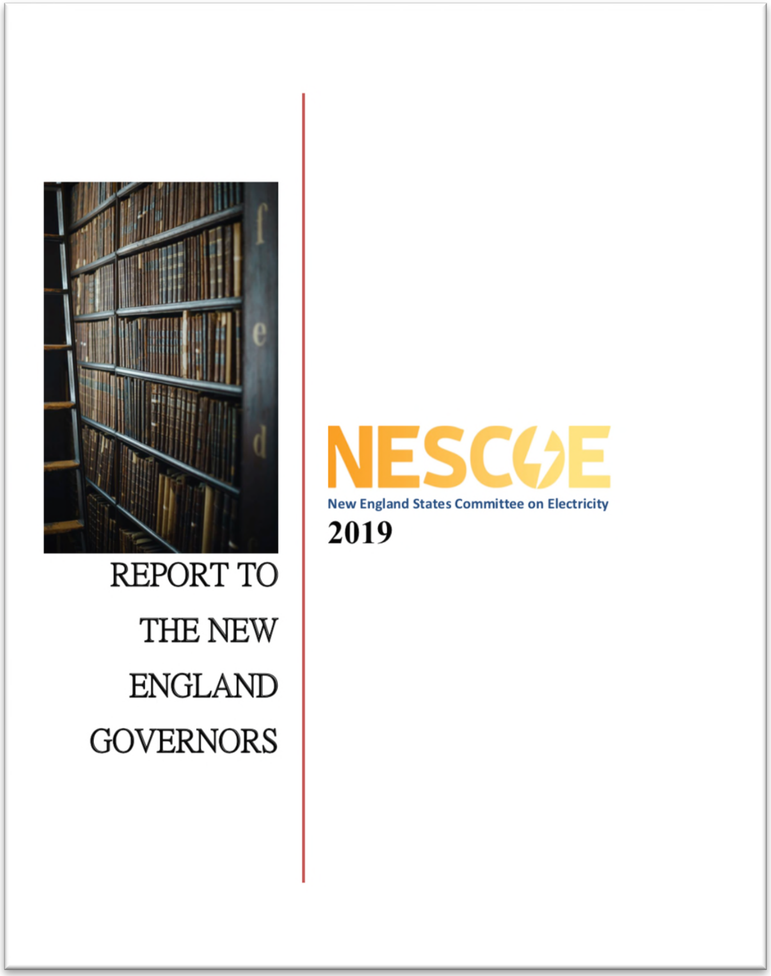
Consistent with Term Sheet, ***2019 Report to the New England Governors***:

- ✓ Reviewed work in 2019
- ✓ Projected policy priorities
- ✓ Provided spending from prior year
- ✓ Projected budget information for upcoming two years

Projected Policy Priorities

- ✓ NESCOE provided to the Governors the ***2019 Annual Report to New England Governors***
- ✓ Report simultaneously released to NEPOOL & ISO-NE & circulated to the Participants Committee
- ✓ NESCOE identified forward looking policy priorities at Section V, pages 17 - 21

Report available at
http://nescoe.com/resource-center/2019-annual-report-july2020/
or go to "Resource Center" --- enter
Annual Report in search bar



REPORT TO
THE NEW
ENGLAND
GOVERNORS

NESCOE
New England States Committee on Electricity
2019

Projected Policy Priorities, update

- ✓ Participate actively in the “Future Grid Study” at Joint Markets and Reliability Committee meetings, and “Future Market Framework” at the Participants Committee, and discussions that follow in technical committees.
- ✓ Actively engage in continuing discussions about ISO New England’s Energy Security Improvement proposal, including but not limited to market mitigation concerns.
- ✓ Following the region’s first Order 1000 Competitive Process to Satisfy Reliability Needs, participate in the ex post review of lessons learned.
- ✓ Continue to advocate for transmission incentives that are just and reasonable where they are currently necessary to cause specific actions that would not otherwise happen, and where, as designed, they deliver recognizable value for electricity customers.

NESCOE Organization & Misc.

Employees

- ✓ Diversity in academic training, skills; blend of private & public sector experience
- ✓ Current total employee level: 5

Office Space

- ✓ 4 Bellows Road, Westborough, MA
  - ✓Current lease through November 30, 2021; anticipate renewal
  - ✓Provides small group meeting space needs
- ✓ Small room in Portsmouth, New Hampshire
  - ✓Current lease through 2020; anticipate renewal

Organizational matters, Con't.

Technical Consultants

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

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

- ✓ Exeter Associates, Inc.
- ✓ Wilson Energy Economics
- ✓ PeterGFlynn, LLC
- ✓ Bob Laurita

Supplement with other expertise, on an as needed basis.

Legal Counsel

Litigation is not the primary means by which NESCOE seeks to accomplish its objectives & thus, greater resource and focus has historically, and thus far in 2020, been on technical consulting. Further, while NESCOE produces most legal pleadings and analysis internally, the frequency and type of litigation brought by others influences the extent to which NESCOE engages outside counsel.

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

5-Year Pro Forma

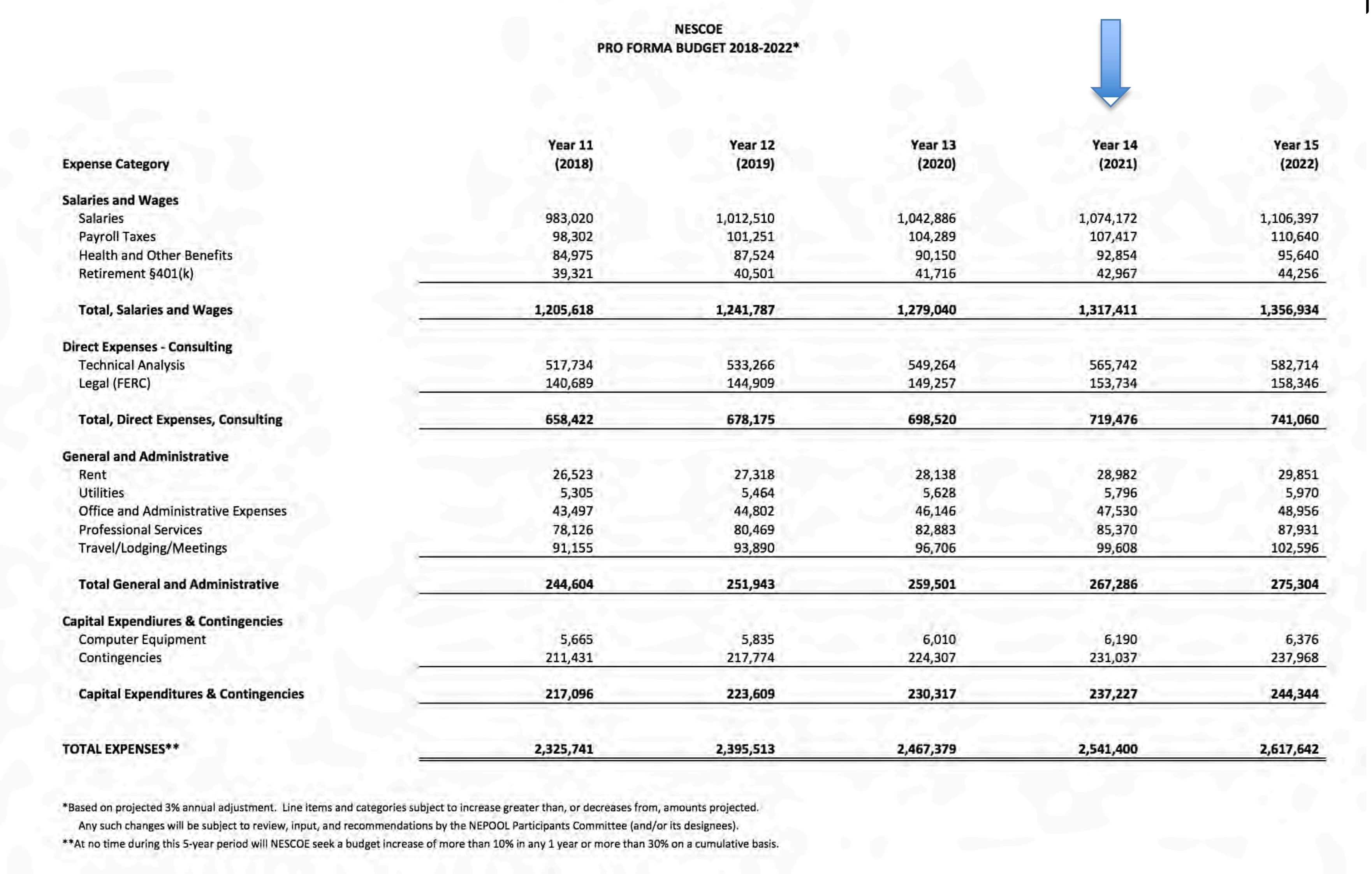
Proposed 2021 budget conforms to 2021 budget in 5-year Pro Forma Framework

2021 Projected Budget in 5-Year Pro Forma:	$2,541,400
2021 Proposed Budget:	$2,428,300
2020 Budget, for reference:	$2,421,056

In relation to 2021 5-year Pro Forma, 2021 Proposed Budget reflects:

- Continued rebalance of technical consulting and legal spending in light of range of proceedings, some of which remain pending
- Reductions in travel and professional services based on recent experience

5-Year Pro Forma, for reference



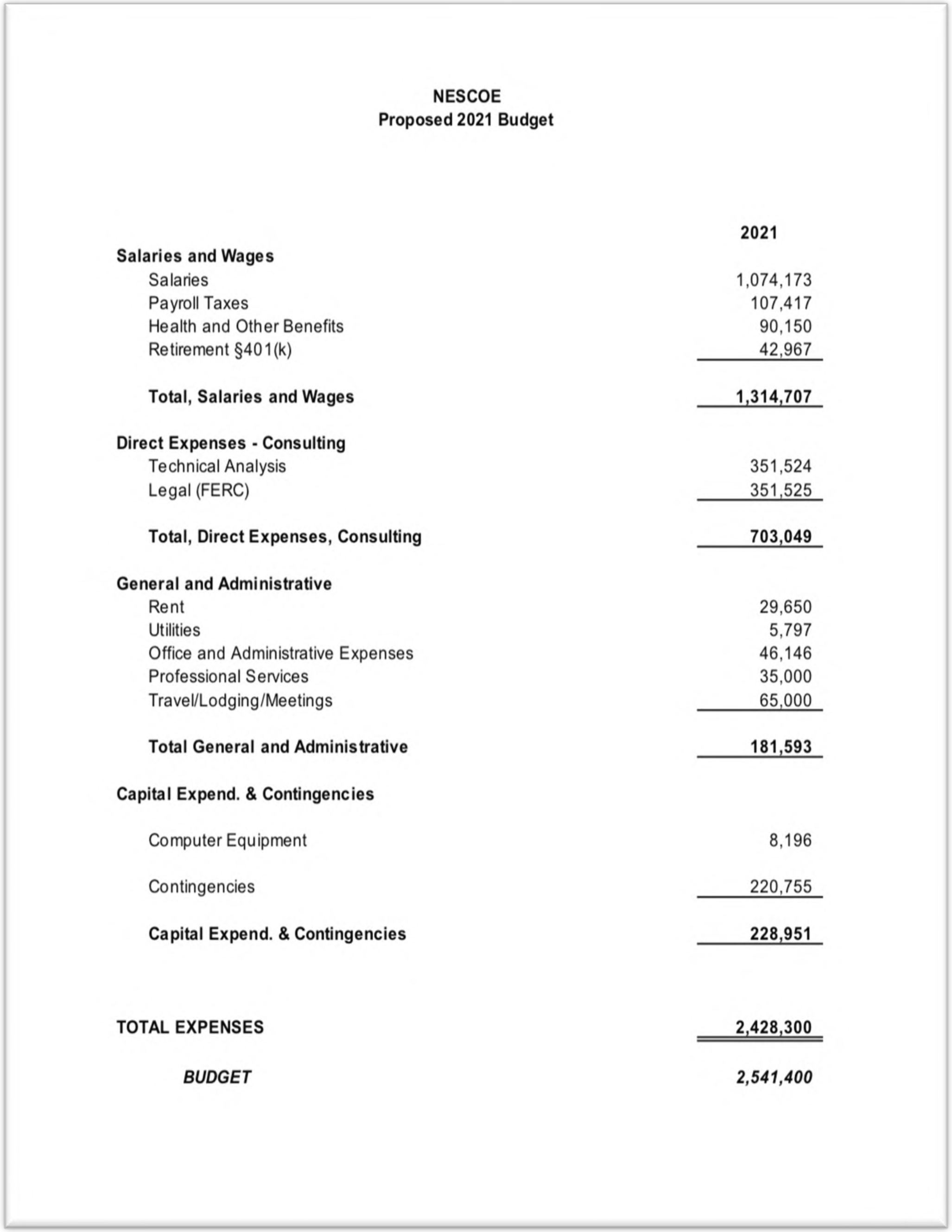
NESCOE
PRO FORMA BUDGET 2018-2022*

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

*Based on projected 3% annual adjustment. Line items and categories subject to increase greater than, or decreases from, amounts projected. Any such changes will be subject to review, input, and recommendations by the NEPOOL Participants Committee (and/or its designees).

**At no time during this 5-year period will NESCOE seek a budget increase of more than 10% in any 1 year or more than 30% on a cumulative basis.

2021 Proposed Budget



NESCOE
Proposed 2021 Budget

	2021
Salaries and Wages	
Salaries	1,074,173
Payroll Taxes	107,417
Health and Other Benefits	90,150
Retirement §401(k)	42,967
Total, Salaries and Wages	**1,314,707**
Direct Expenses - Consulting	
Technical Analysis	351,524
Legal (FERC)	351,525
Total, Direct Expenses, Consulting	**703,049**
General and Administrative	
Rent	29,650
Utilities	5,797
Office and Administrative Expenses	46,146
Professional Services	35,000
Travel/Lodging/Meetings	65,000
Total General and Administrative	**181,593**
Capital Expend. & Contingencies	
Computer Equipment	8,196
Contingencies	220,755
Capital Expend. & Contingencies	**228,951**
TOTAL EXPENSES	**2,428,300**
BUDGET	***2,541,400***

2019 & 2020 Spending & Implications for 2021

Unspent funds in any year credited toward future year

2019 Total Spending:	$1,259,511 *
2020 Spending to end of June:	$ 717,083
2020 Projected Year End:	$1,671,412 *

* Cumulative prior years' true up, including 2018, was reflected in the 2020 revenue requirement and rates. The 2019 true up will be reflected in the 2021 revenue requirement and rates (see following slide). Any 2020 true up will be reflected in the 2022 revenue requirements and rates.

2021 Projected Billing Rate

With thanks to ISO-NE for calculations -

2021 Budget:	$2,428,300
Less 2019 True Up:	($1,067,405)
Total Revenue Recovery:	$1,360,895
Divided by Total Network Load:	227,402,228

(*total network load from 2020 ISO-NE tariff; no escalation or reduction used in calculation)*

~~**2021 Schedule 5 *Estimated* Rate $0.00598 per kW-month**~~

NEW: 2021 Schedule 5 *Actual* Rate $0.00626 per kW-month

(Actual Rate based on now finalized 2021 Network Load factor:
$1,360,895 (revenue requirement) ÷ 217,262,589 (2021 Network Load) = $0.00626

Thank you.

Questions?

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Eric Runge, NEPOOL Counsel

DATE: September 24, 2020

RE: Vote on HQICC and ICR Values for FCA15

At the October 1, 2020 Participants Committee meeting, you will be asked to support the following proposed sets of values: (i) Hydro-Quebec Interconnection Capability Credit values (the "HQICC Values"); and (ii) Installed Capacity Requirement ("ICR") values, and the related demand curves (collectively, the "ICR Values") to be used for Forward Capacity Auction 15 ("FCA15").[1] With only a few opposed and abstaining, the Reliability Committee has recommended Participants Committee support for both sets of values.[2]

The HQICC Values and ICR Values for FCA15 were developed by the ISO, reviewed with the Power Supply Planning Committee, and reviewed with and voted on by the Reliability Committee. At its September 23, 2020 meeting, the Reliability Committee recommended in separate voice votes that the Participants Committee support the HQICC Values and the ICR Values.

For the HQICC Values vote, there were only two opposed, and three abstentions, with Cross Sound Cable and LIPA opposing based on their long-standing objection to the lack of recognition of reliability value of Cross Sound Cable in calculating tie benefits and the ICR. For the ICR Values vote there were only three opposed, and three abstentions, with Cross Sound Cable and LIPA opposing based on the objection noted above and Exelon opposing but not expressing a basis for its opposition.

The HQICC Values for FCA15 proposed by the ISO and recommended by the Reliability Committee are 883 MW for each month of the 2024-2025 Capacity Commitment Period (June through May).

The ICR Values for FCA15 proposed by the ISO and recommended by the Reliability Committee are as follows:

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[1] Background materials have been included with this memorandum. While the HQICC Values and ICR Values are interrelated, in the past separate issues have been raised with respect to one or the other, and accordingly they have been voted separately.

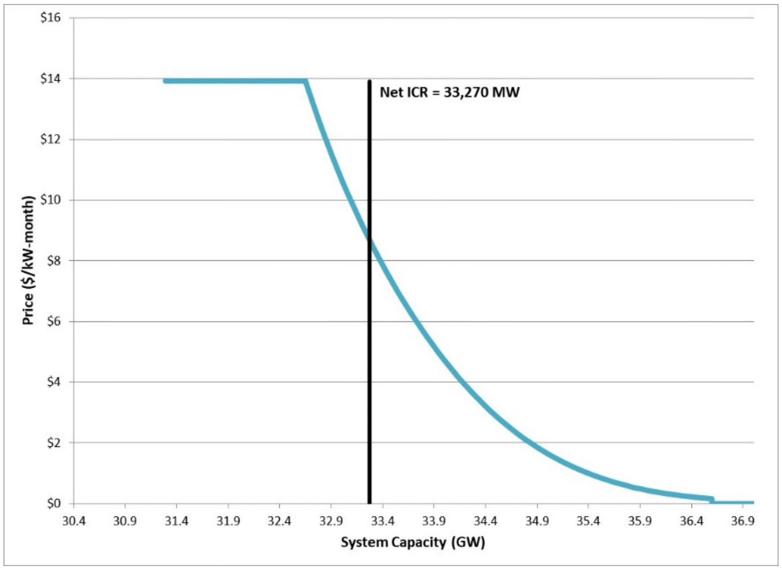
[2] The Notice of Actions for the September 23, 2020 meeting of the Reliability Committee is available here: https://www.iso-ne.com/static-assets/documents/2020/09/092320_rc_actions_letter.pdf.

ICR/LSR/MCL

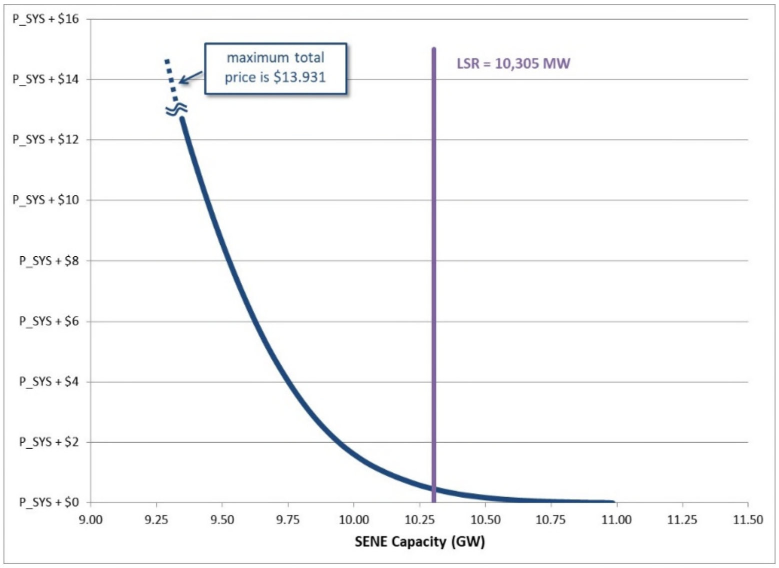
	2024-2025 Capacity Commitment Period ICR Values (MW)
Installed Capacity Requirement	34,153
Net Installed Capacity Requirement	33,270
Southeast New England Local Sourcing Requirement	10,305
Maine Maximum Capacity Limit	4,145
Northern New England Maximum Capacity Limit	8,680

Demand Curves

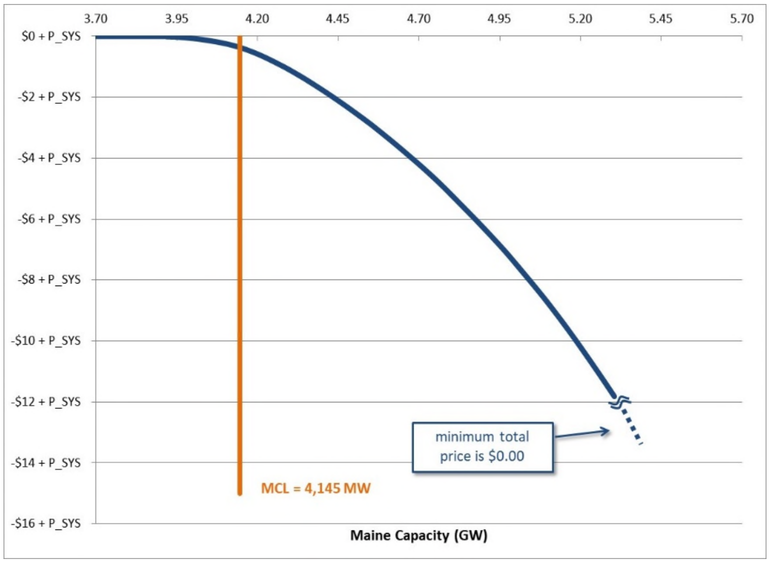
2024-2025 Capacity Commitment Period System-wide Capacity Demand Curve:



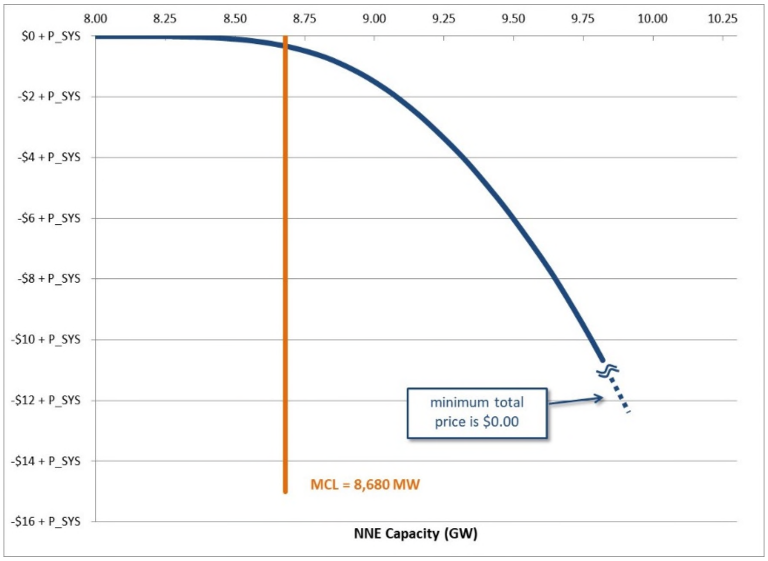
2024-2025 Capacity Commitment Period Southeast New England Capacity Zone Demand Curve:



2024-2025 Capacity Commitment Period Maine Capacity Zone Demand Curve:



2024-2025 Capacity Commitment Period Northern New England Capacity Zone Demand Curve:



The following resolutions, which require a minimum 60% Vote for approval, could be used for Participants Committee consideration of these items:

> 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 [any changes agreed to at the meeting and] 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 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 [any changes agreed to at the meeting and] such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee.

SEPTEMBER 23, 2020 | RELIABILITY COMMITTEE WEBEX

ICR & Related Values

For Capacity Commitment Period 2024-2025 Fifteenth Forward Capacity Auction (FCA 15)

Quan Chen, Fei Zeng, and Manasa Kotha

RESOURCE STUDIES AND ASSESSMENTS

Today's Presentation

- Review the ICR and Related Values for FCA 15 to be Acted Today
- Answer any questions you may have regarding these values
- Request your Action on RC Motions of ICR and Related Values for FCA 15

Notes:

- The ICR, net ICR, Local Resource Adequacy, Transmission Security Analysis, Local Sourcing Requirement, Maximum Capacity Limit, the marginal Reliability Impact system and zonal Demand Curves and the HQICCs are collectively referred to as the ICR and Related Values
- Please see Appendix for all acronyms

FCA 15 ICR-Related Values Development Schedule

Date	Topic
May 24	PSPC reviewed the 2020 ICR-Related values development schedule for the FCM auctions to be conducted in 2021
June 30	PSPC reviewed FCA 15 ICR-Related Values calculation assumptions
August 14	PSPC reviewed tie benefits study results
August 25	PSPC to review proposed FCA 15 ICR-Related Values
September 1	RC review proposed FCA 15 ICR-Related Values
September 23	RC review/vote proposed FCA 15 ICR-Related Values
October 1	PC review/vote of proposed ICR-Related Values
By November 10	File with FERC FCA 15 ICR-Related Values

REVIEW THE ICR AND RELATED VALUES FOR FCA 15

Summary of FCA 15 Tie Benefits Study Results

Interface	FCA 15 Tie Benefits Amount (MW)
Maritimes	454
HQ Phase II (HQICC)	883
Highgate	140
New York AC ties	258
CSC	0
Total Tie Benefits	**1,735**

Results of the FCA 15 Tie Benefits Study are located at: https://www.iso-ne.com/static-assets/documents/2020/09/a2_fca_15_tie_benefits_presentation.pptx

ISO Proposed FCA 15 ICR-Related Values for CCP 2024-2025 (MW)

2024-2025 FCA 15	New England	Southeast New England	Maine	Northern New England
Peak Load (50/50) net of BTM PV	29,303	12,679	2,230	5,645
Peak Load (90/10) net of BTM PV	31,377	13,739	2,332	5,908
Existing Capacity Resources	33,332	9,665	3,483	8,324
Installed Capacity Requirement	34,153			
HQICCs	883			
Net ICR (ICR minus HQICCs)	33,270			
Local Sourcing Requirement		10,305		
Maximum Capacity Limit			4,145	8,680

Details relating to the development of the FCA 15 ICR and Related Values are located at: https://www.iso-ne.com/static-assets/documents/2020/08/a2_fca_15_icr_and_related_values.pptx

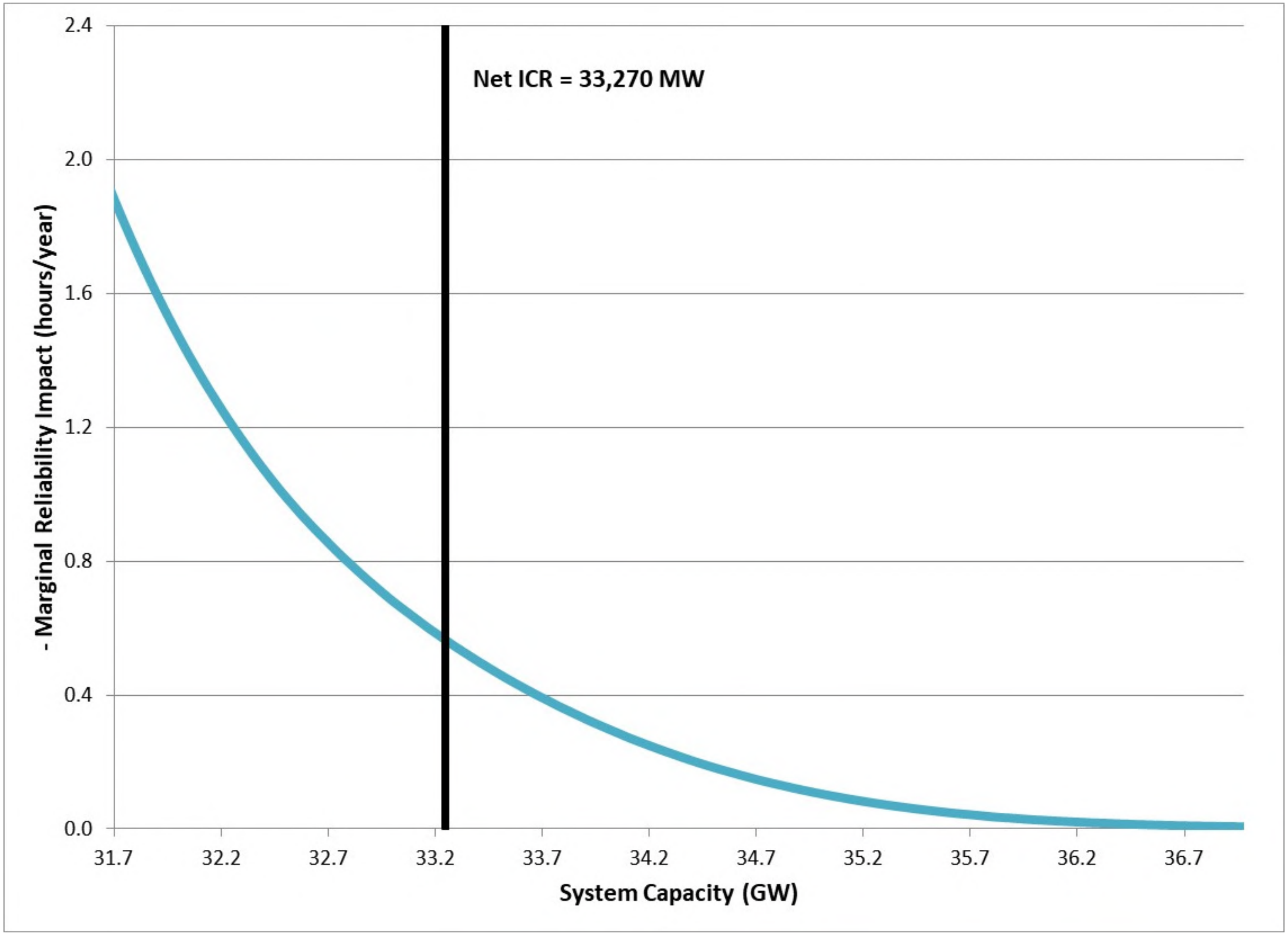
Notes:

- The Existing Capacity Resources value reflects the existing resources with Qualified Capacity for FCA 15 at the time of the ICR calculation and reflects applicable retirements and terminations
- 50/50 and 90/10 peak loads, net of BTM PV (includes both transportation and heating electrification forecast) are shown for informational purpose

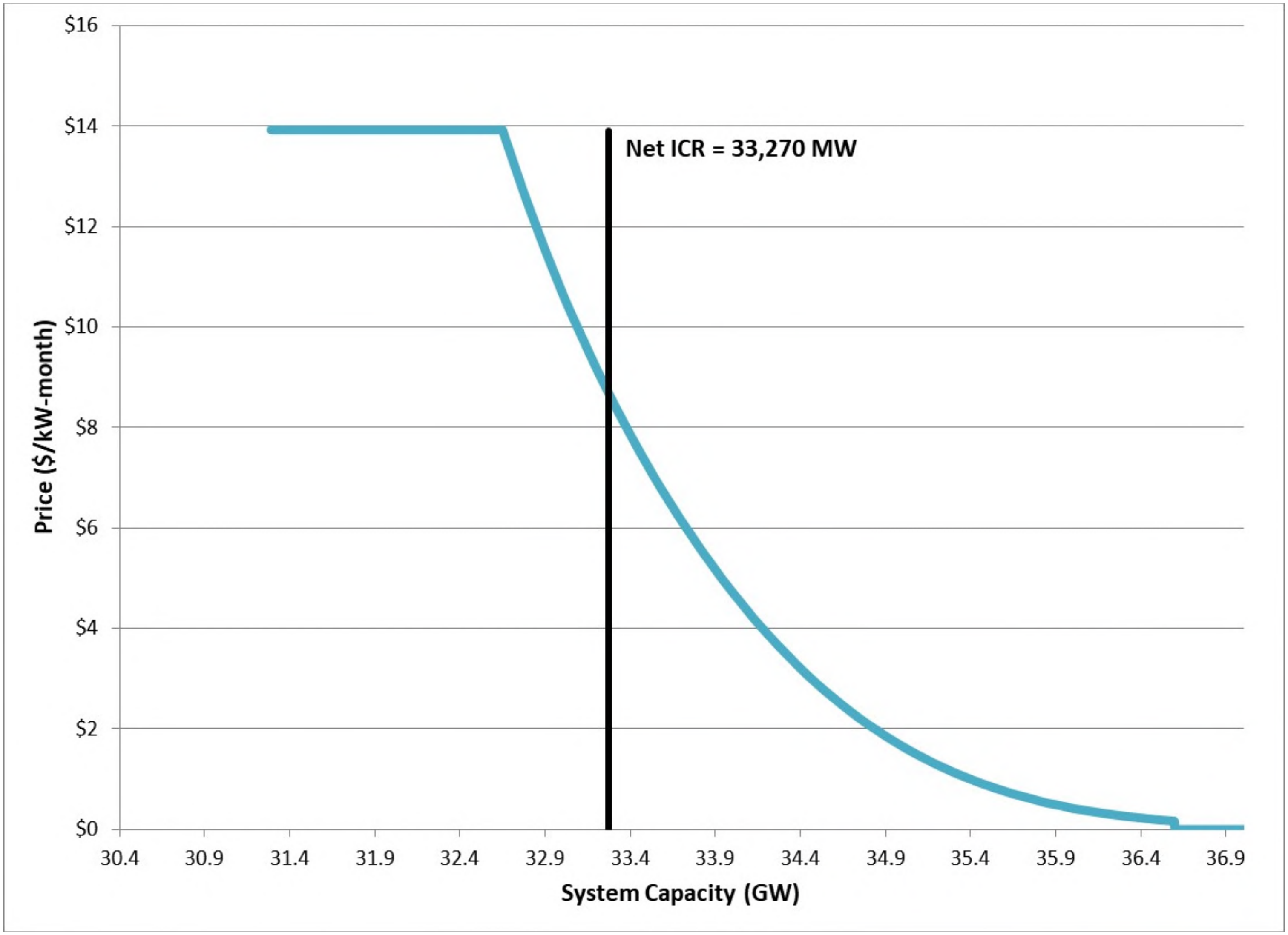
FCA 15 DEMAND CURVES

The FCA 15 MRI based Demand Curve Values are located at: https://www.iso-ne.com/static-assets/documents/2020/09/a2_fca_15_tie_benefits_presentation.pptx

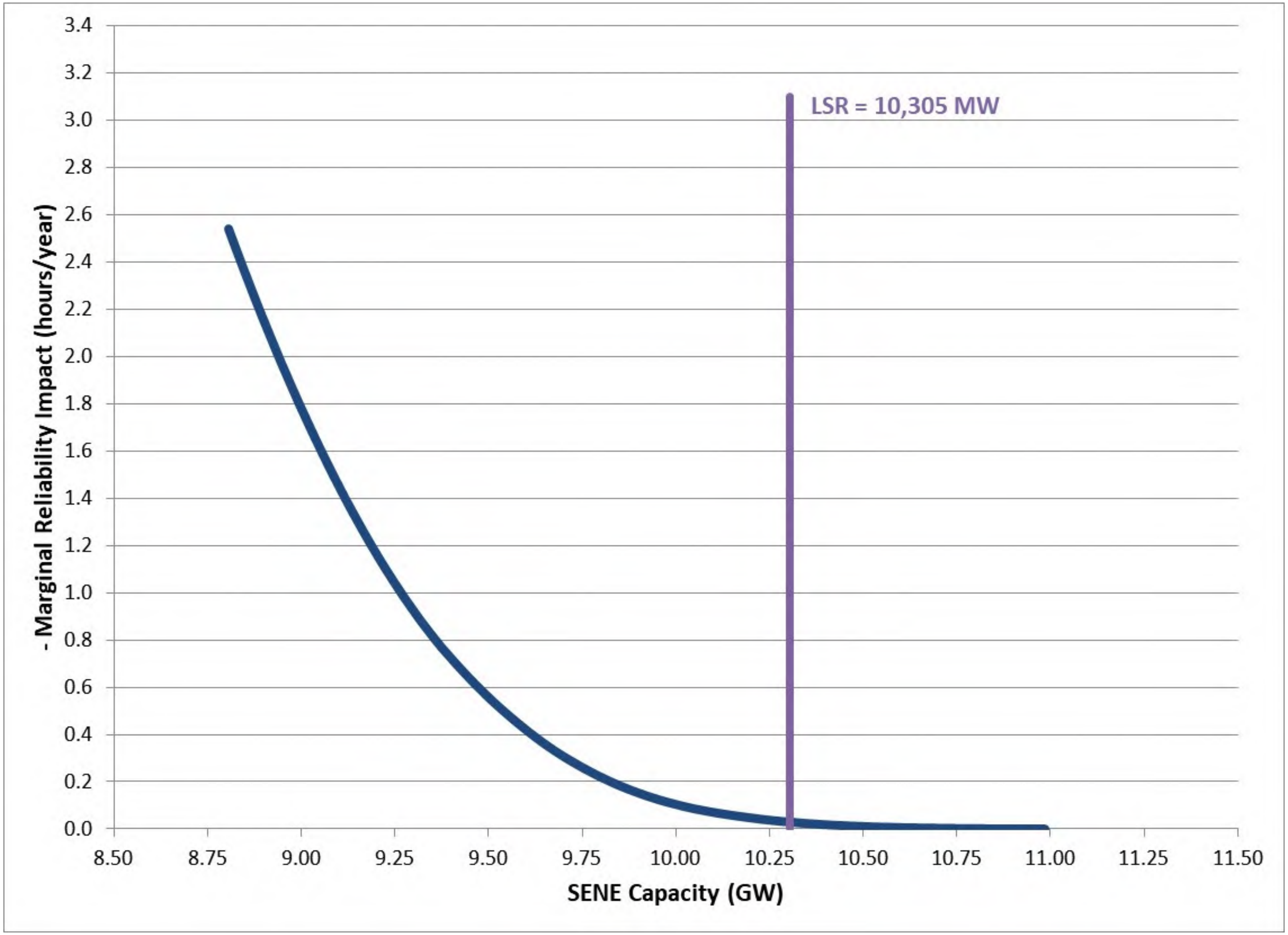
FCA 15 System-wide MRI Curve



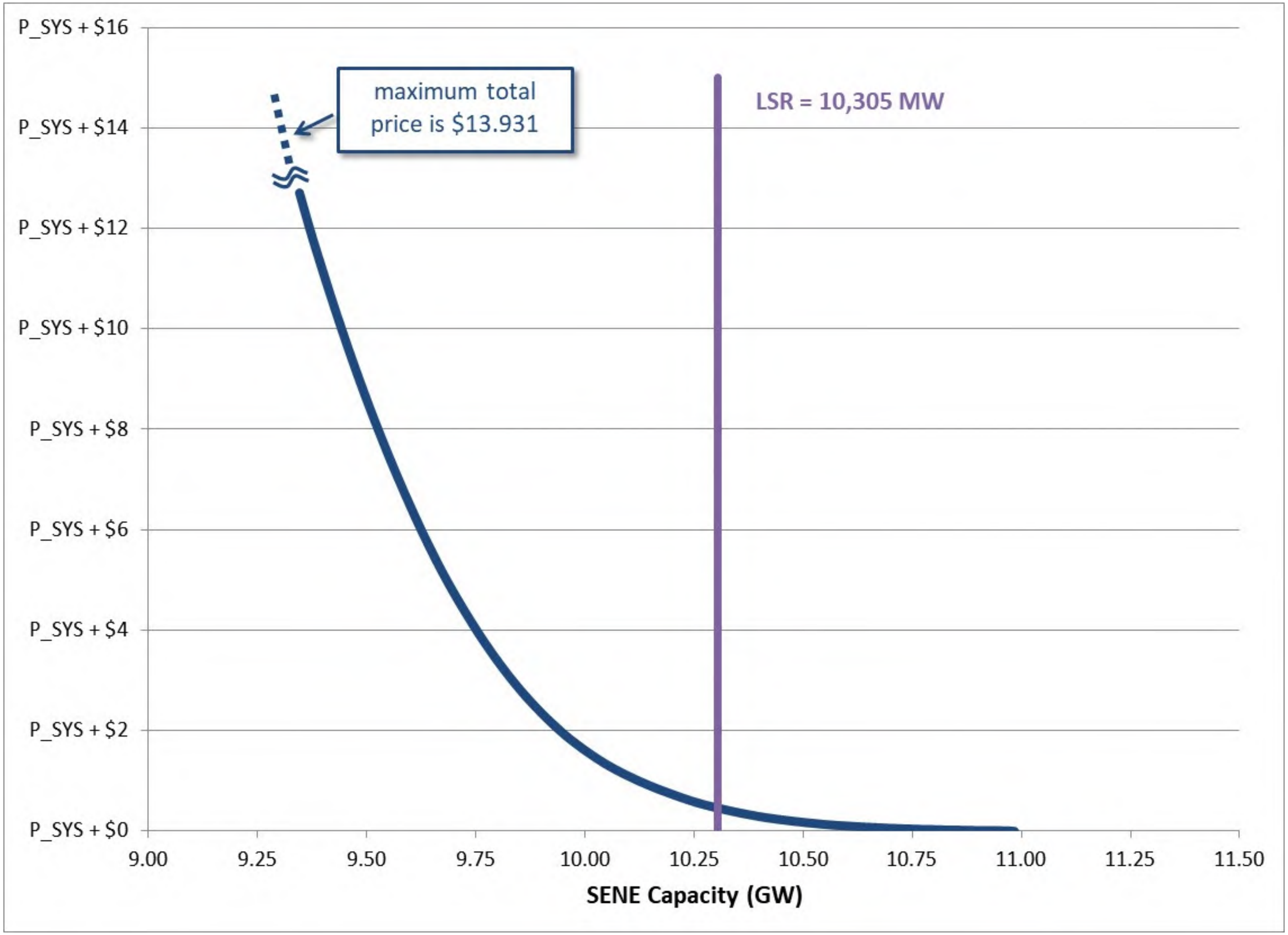
FCA 15 System-wide Demand Curve



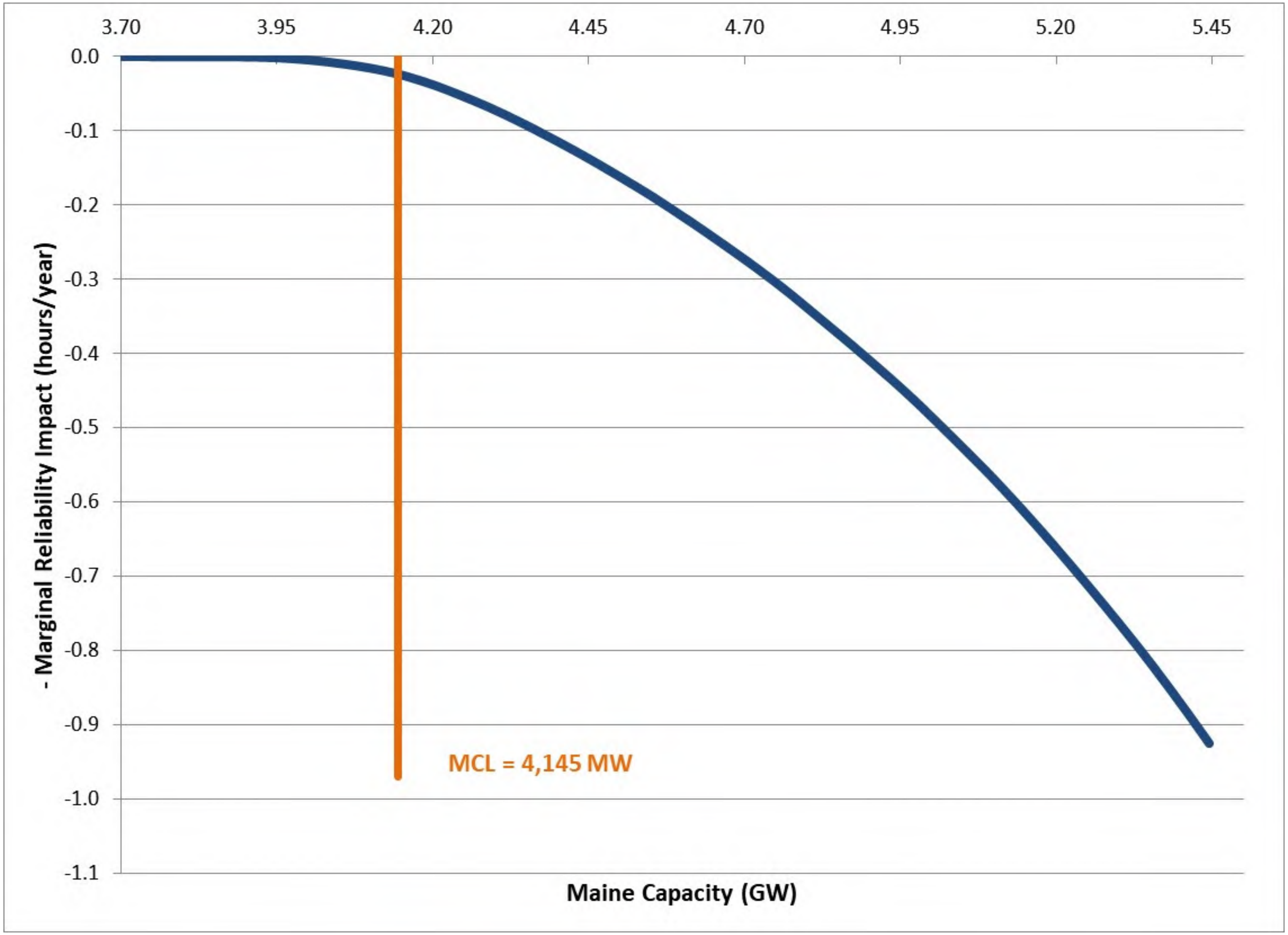
FCA 15 SENE MRI Curve



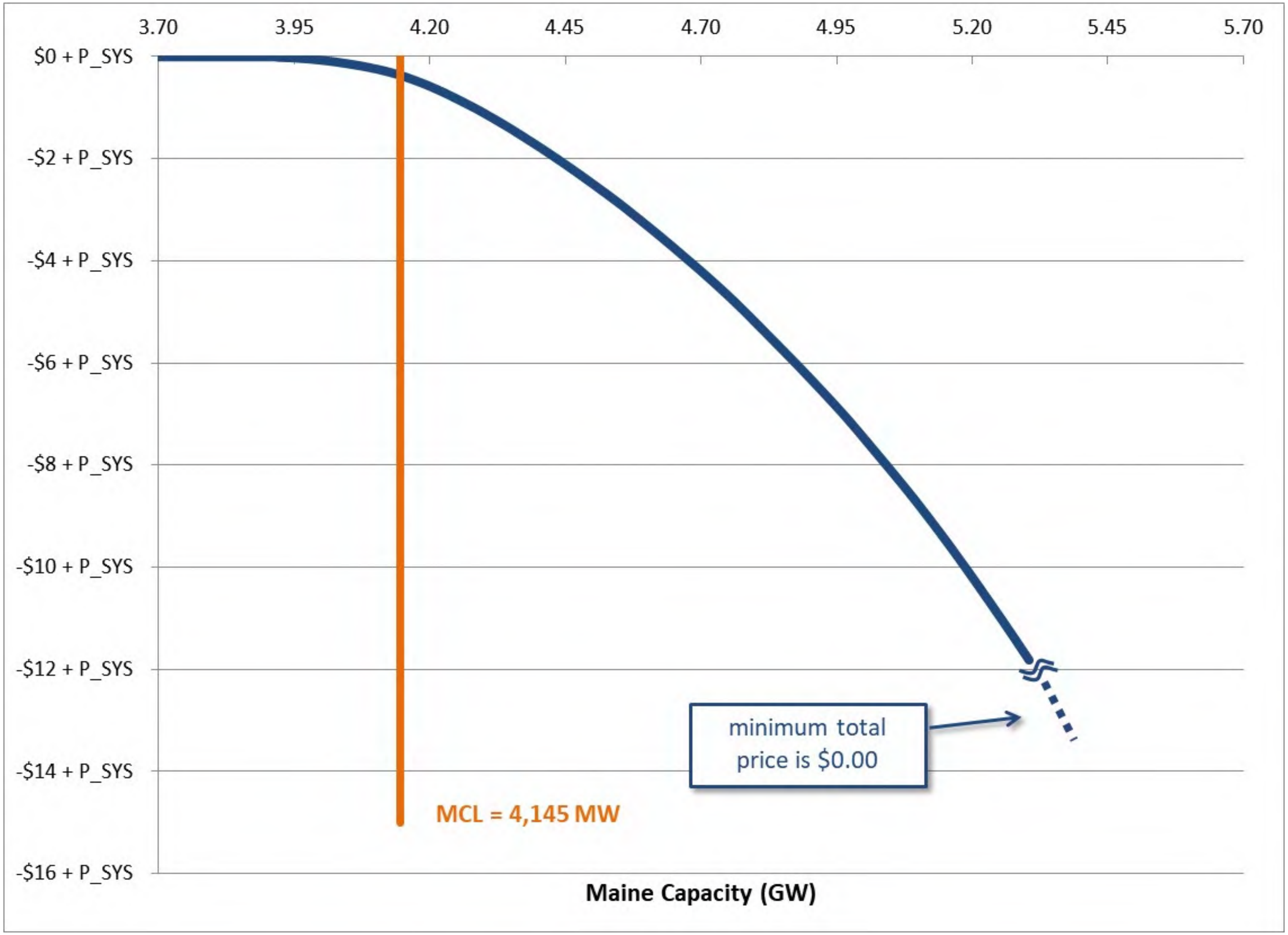
FCA 15 SENE Demand Curve



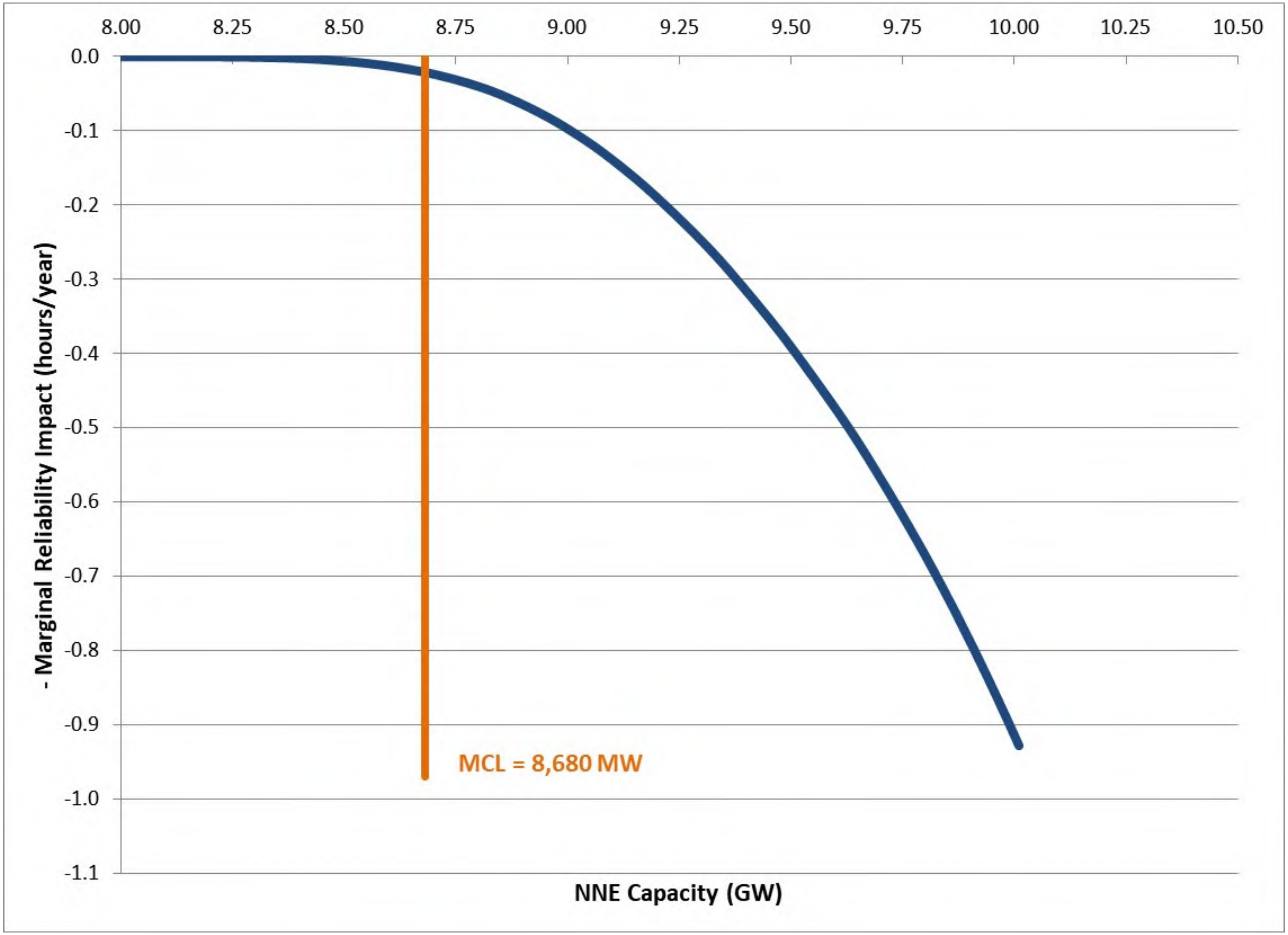
FCA 15 Maine MRI Curve



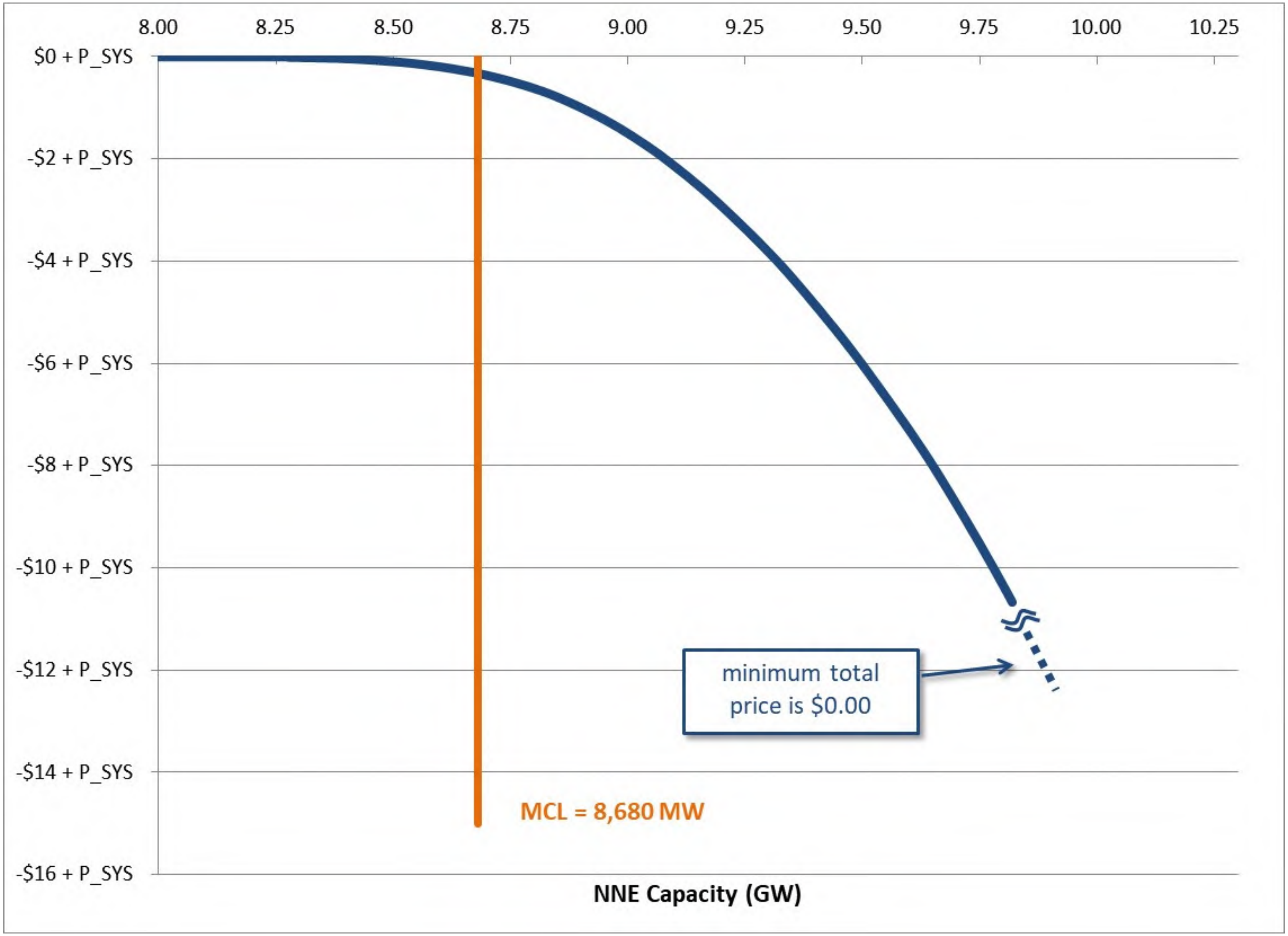
FCA 15 Maine Demand Curve



FCA 15 NNE MRI Curve



FCA 15 NNE Demand Curve



RELIABILITY COMMITTEE MOTIONS
FCA 15 ICR AND RELATED VALUES

HQICC Motion

Resolved, the Reliability Committee recommends Participants Committee support for the following megawatt values that represent the Hydro-Québec Interconnection Capability Credit (HQICC) values for the 15th Forward Capacity Auction, which is associated with the 2024-2025 Capacity Commitment Period:

2024-2025 Capacity Commitment Period Month	**HQICC Values (MW)**
June	883
July	883
August	883
September	883
October	883
November	883
December	883
January	883
February	883
March	883
April	883
May	883

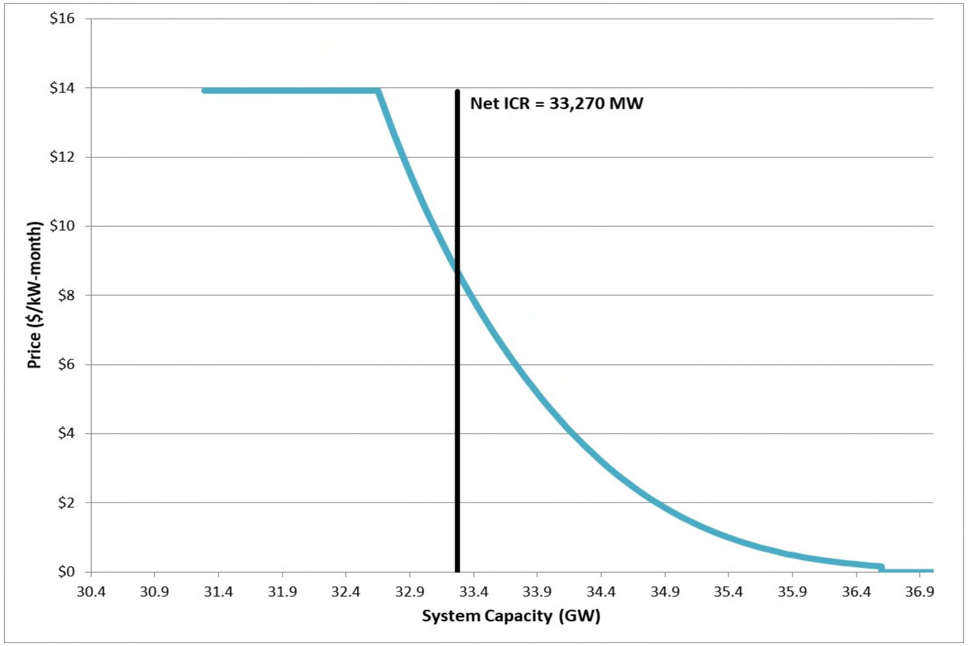
ICR/LSR/MCL/Demand Curves Motion

Resolved, the Reliability Committee recommends Participants Committee support for the following megawatt values that represent the New England Installed Capacity Requirement (ICR), Net Installed Capacity Requirement (Net ICR), Southeast New England Local Sourcing Requirement (LSR), Maine Maximum Capacity Limit (MCL), Northern New England MCL, and Capacity Demand Curves for the System and Capacity Zones based on the Marginal Reliability Impact (MRI) methodology for the 15th Forward Capacity Auction, which is associated with the 2024-2025 Capacity Commitment Period:

	2024-2025 Capacity Commitment Period ICR Values (MW)
Installed Capacity Requirement	34,153
Net Installed Capacity Requirement	33,270
Southeast New England Local Sourcing Requirement	10,305
Maine Maximum Capacity Limit	4,145
Northern New England Maximum Capacity Limit	8,680

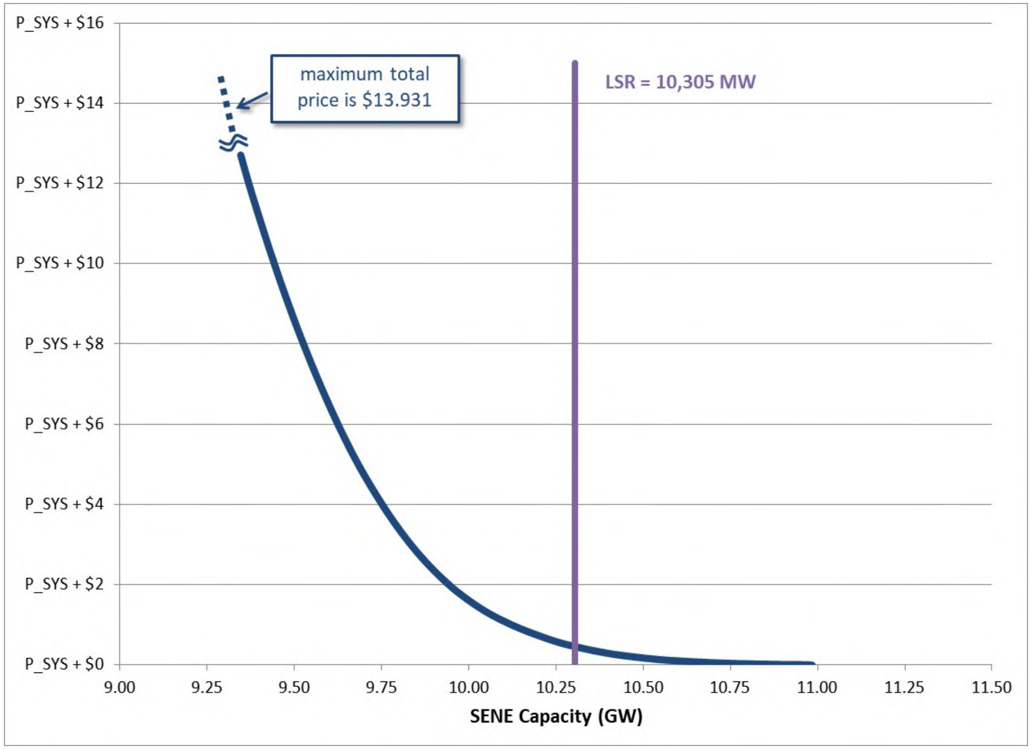
ICR/LSR/MCL/Demand Curves Motion, cont.

2024-2025 Capacity Commitment Period System-wide Capacity Demand Curve:



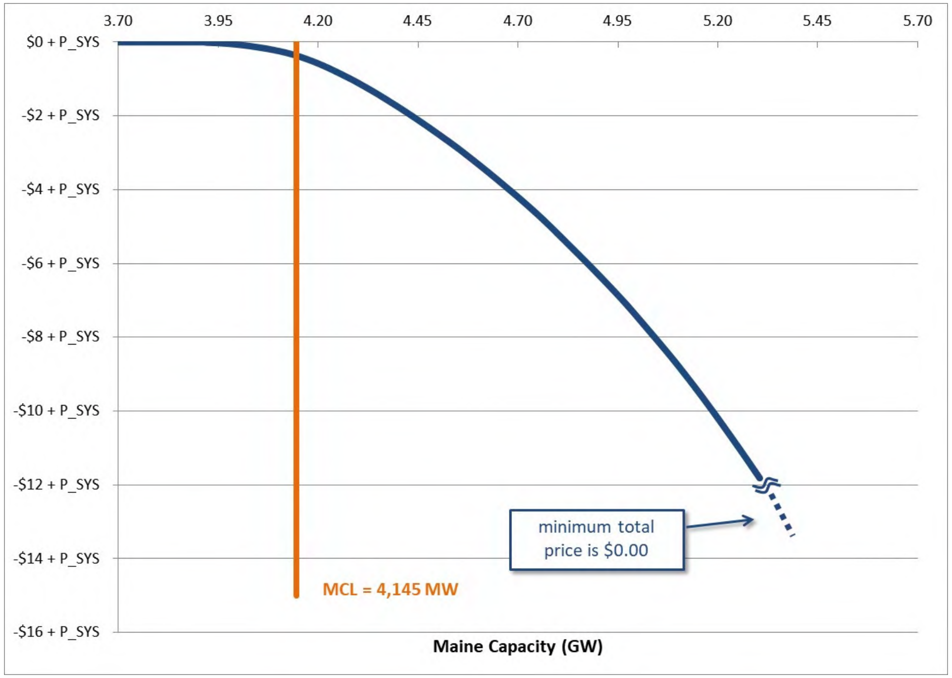
ICR/LSR/MCL/Demand Curves Motion, cont.

2024-2025 Capacity Commitment Period Southeast New England Capacity Zone Demand Curve:



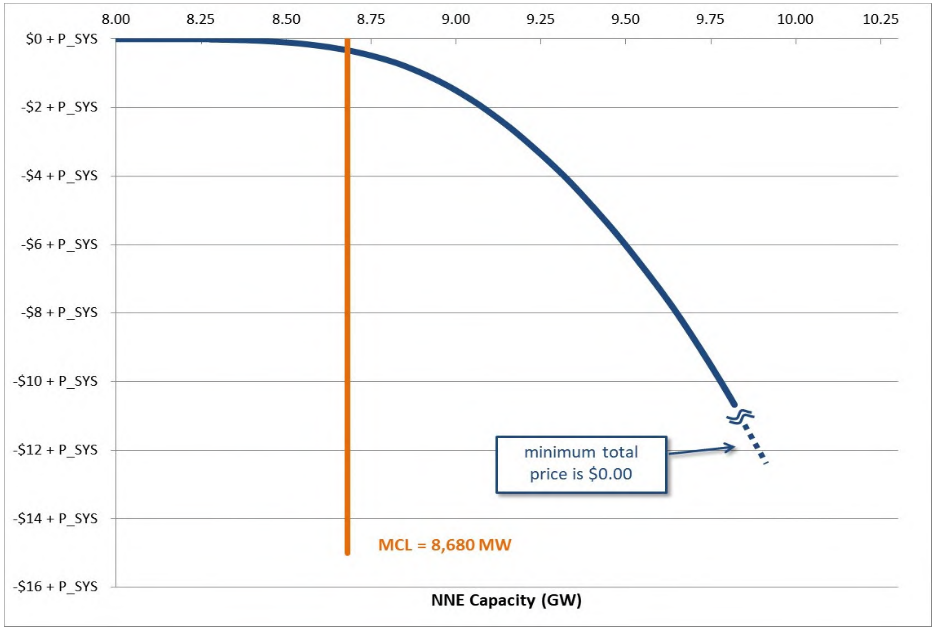
ICR/LSR/MCL/Demand Curves Motion, cont.

2024-2025 Capacity Commitment Period Maine Capacity Zone Demand Curve:



ICR/LSR/MCL/Demand Curves Motion, cont.

2024-2025 Capacity Commitment Period Northern New England Capacity Zone Demand Curve:



Questions

APPENDIX

*Acronyms for ICR-Related Values**

*Not all acronyms are used in this presentation

Acronyms

- ADCR – Active Demand Capacity Resource
- ALCC – Additional Load Carrying Capability
- APk – Gross peak load net of BTM PV
- ARA – Annual Reconfiguration Auction
- ART – Annual Reconfiguration Transaction
- BTM PV – Behind-the-meter Photovoltaic
- CCP – Capacity Commitment Period
- CDD – Cooling Degree Days
- CELT – Capacity, Energy, Loads and Transmission
- CSC – Cross Sound Cable
- CSO – Capacity Supply Obligation
- CT – Connecticut
- DR – Demand Resource
- EE – Energy Efficiency
- EFORd – Equivalent Forced Outage Rate on Demand

Acronyms, cont.

- FCA – Forward Capacity Auction
- FCM – Forward Capacity Market
- FERC – Federal Energy Regulatory Commission
- HQICCs – Hydro-Quebec Interconnection Capability Credits
- ICR – Installed Capacity Requirement
- ISO – ISO New England
- LRA – Local Resource Adequacy
- LSR – Local Sourcing Requirement
- MARS -Multi-Area Reliability Simulation
- MCL – Maximum Capacity Limit
- MRI – Marginal Reliability Impact
- NEPOOL – New England Power Pool
- Net ICR – ICR minus HQICCs
- NNE – Northern New England

Acronyms, cont.

- NPCC – Northeast Power Coordinating Council
- OP-4 – Operating Procedure No. 4, Action During a Capacity Deficiency
- PAC – Planning Advisory Committee
- PC – Participants Committee
- PK – Peak (gross load forecast)
- PSPC – Power Supply Planning Committee
- RC – Reliability Committee
- RI – Rhode Island
- SEMA – Southeastern Massachusetts
- SENE – Southern New England
- SWCT – Southwest Connecticut
- TSA – Transmission Security Analysis
- VR – Voltage Reduction
- WEFORd – Weighted Equivalent Forced Outage Rated on Demand

SEPTEMBER 23, 2020 | RELIABILITY COMMITTEE WEBEX

AGENDA ITEM 8.0

Response to Tie Benefits Question Raised at the September 1 RC Meeting

For Capacity Commitment Period 2024-2025
Fifteenth Forward Capacity Auction (FCA 15)

Fei Zeng

RESOURCE STUDIES AND ASSESSMENTS

Question Regarding FCA 15 Tie Benefits September 1, 2020 RC Committee Meeting

For Commitment Periods preceding FCA15, New England had a largest single generation contingency of 1,400 MW (Mystic 8 & 9). In that circumstance, assuming Phase II imports to 1,400 MW did not increase ten minute reserve requirement. However, with retirement of Mystic 8 & 9, no internal generator contingency is greater than 1,250 MW. So, if modelled tie benefit flows above 1,250 MW in any Monte Carlo pull, this would seem to overstate the contribution since any increase in flow above 1,250 MW would increase the first contingency….making situation worse.

ISO-NE Response

During the Monte Carlo simulation in the tie benefits study, the emergency flow from Phase II (along with all other ties) are in response to the shortage conditions in New England and New York caused by any combination of random generation contingencies in these two control areas at any given hour. The magnitude of the flow depends on the amount of deficits in New England and New York, and the amount of emergency assistance Quebec can provide, while also respecting the import capability. The emergency flow New England can obtain during the shortage condition is used to serve load and to maintain 700 MW of minimum operating reserve requirement prior to firm load shedding. The emergency flow does not present itself as a contingency since the system has exhausted all the available internal resources at that point, and the operating reserve is allowed to deplete to the minimum requirement. The tie benefits contribution of Phase II flow is measured as the equivalent capacity to reduce the loss of load probability in New England, and has been properly captured as the weighted average over the thousands of replication during the Monte Carlo simulation process.

Questions

ISO new england

memo

To: Participants Committee

From: Marc Lyons, Secretary, Reliability Committee

Date: September 23, 2020

Subject: Actions of the Reliability Committee from the September 23, 2020 Meeting

This memo is to notify the Participants Committee ("PC") of the actions taken by the Reliability Committee ("RC") at its September 23, 2020 meeting. All Sectors had a quorum with the exception of End User.

(Agenda Item 3.1) Meeting Minutes

ACTION: APPROVED

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

Resolved, the Reliability Committee recommends that ISO New England Inc. approve the minutes of the following RC meetings as distributed to the committee for the September 23, 2020 meeting:

- August 18, 2020

The motion was then voted. Based on a voice vote, the motion passed with none opposed and no abstentions.

(Agenda Item 6.1) (66.67% Vote) Middletown 10 AVR Replacement Project - Proposed Plan Application (PPA) NRG-20-X01

ACTION: APPROVED

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

Resolved, the Reliability Committee recommends that ISO New England Inc. determine that implementation of the Middletown 10 AVR Replacement Project described in Proposed Plan Application ("PPA"), NRG-20-X01 from NRG Power Marketing ("NRG"), as detailed in their ?? transmittal to ISO New England and distributed to the committee for the September 23, 2020 meeting, will not have a significant adverse effect on the stability, reliability or operating characteristics of the transmission facilities of the applicant, the transmission facilities of another Transmission Owner or the system of a Market Participant.

The motion was then voted. Based on a voice vote, the motion passed with none opposed and no abstentions.

(Agenda Item 6.2) (66.67% Vote) Sudbury Substation to Hudson Light and Power Substation 115 kV Underground Cable Project Rev. 1 - Proposed Plan Application (PPA) ES-16-T07-Rev. 1

ACTION: APPROVED

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

Resolved, the Reliability Committee recommends that ISO New England Inc. determine that implementation of the Sudbury Substation to Hudson Light and Power Substation 115 kV Underground Cable Project Rev. 1 described in Proposed Plan Application ("PPA") ES-16-T07 Rev. 1 from Eversource Energy ("ES"), as detailed in their September 10, 2020 transmittal to ISO New England and distributed to the committee for the September 23, 2020 meeting, will not have a significant adverse effect on the stability, reliability or operating characteristics of the transmission facilities of the applicant, the transmission facilities of another Transmission Owner or the system of a Market Participant.

The motion was then voted. Based on a voice vote, the motion passed with none opposed and no abstentions.

(Agenda Item 8.0) (60.0% Vote) Tie Benefits and Installed Capacity Requirements and Related Values for Capacity Commitment Period (CCP) 2024/2025 (FCA 15)

HQICC Motion

ACTION: APPROVED

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

Resolved, the Reliability Committee recommends Participants Committee support for the following megawatt values that represent the Hydro-Québec Interconnection Capability Credit (HQICC) values for the 15th Forward Capacity Auction, which is associated with the 2024-2025 Capacity Commitment Period:

2024-2025 Capacity Commitment Period Month	HQICC Values (MW)
June	883
July	883
August	883
September	883
October	883
November	883
December	883
January	883
February	883
March	883
April	883
May	883

The motion was then voted. Based on a voice vote, the motion passed with two opposed (2 Supplier Sector) and three abstentions (3 Supplier Sector).

ICR/LSR/MCL/Demand Curves Motion

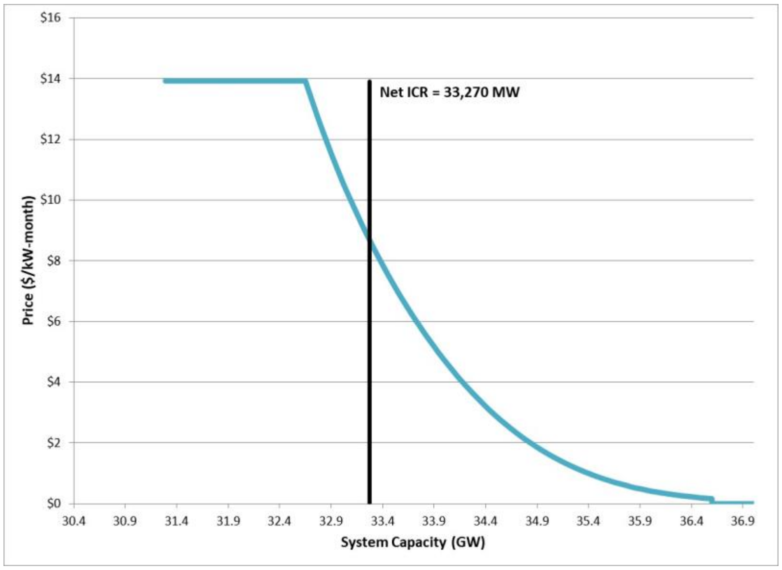
ACTION: APPROVED

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

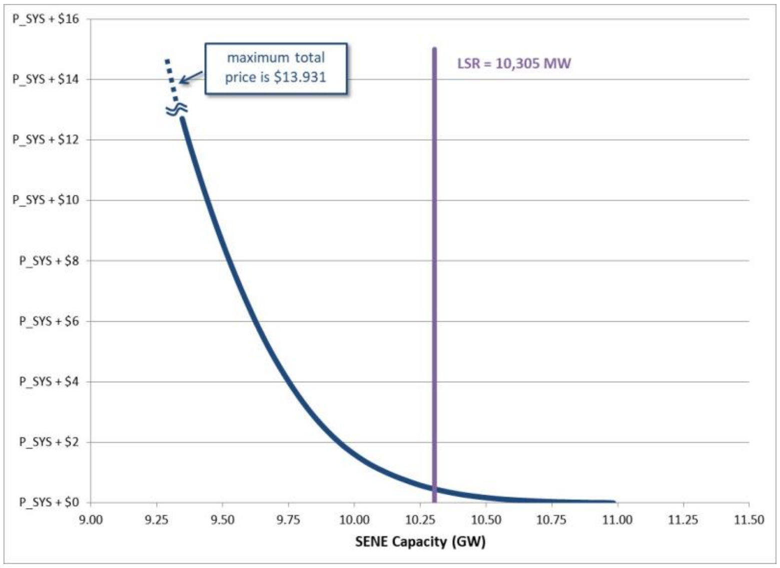
Resolved, the Reliability Committee recommends Participants Committee support for the following megawatt values that represent the New England Installed Capacity Requirement (ICR), Net Installed Capacity Requirement (Net ICR), Southeast New England Local Sourcing Requirement (LSR), Maine Maximum Capacity Limit (MCL), Northern New England MCL, and Capacity Demand Curves for the System and Capacity Zones based on the Marginal Reliability Impact (MRI) methodology for the 15th Forward Capacity Auction, which is associated with the 2024-2025 Capacity Commitment Period:

	2024-2025 Capacity Commitment Period ICR Values (MW)
Installed Capacity Requirement	34,153
Net Installed Capacity Requirement	33,270
Southeast New England Local Sourcing Requirement	10,305
Maine Maximum Capacity Limit	4,145
Northern New England Maximum Capacity Limit	8,680

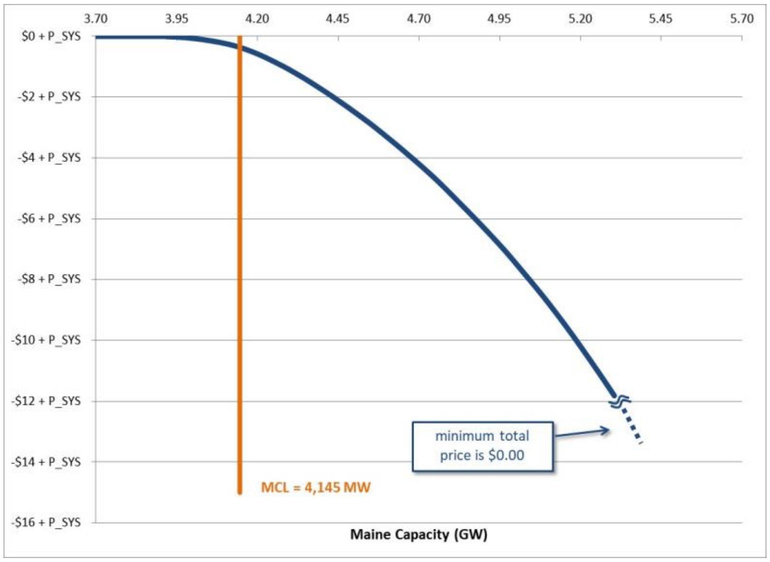
2024-2025 Capacity Commitment Period System-wide Capacity Demand Curve:



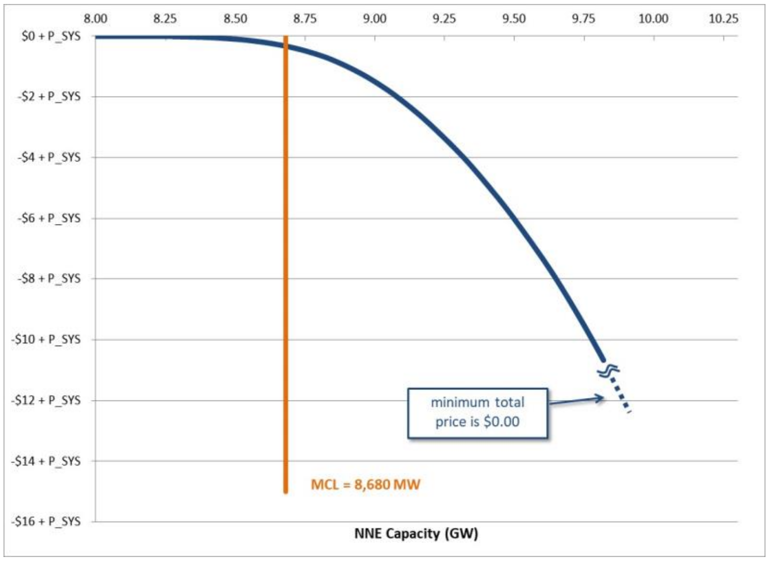
2024-2025 Capacity Commitment Period Southeast New England Capacity Zone Demand Curve:



2024-2025 Capacity Commitment Period Maine Capacity Zone Demand Curve:



2024-2025 Capacity Commitment Period Northern New England Capacity Zone Demand Curve:



The motion was then voted. Based on a voice vote, the motion passed with three opposed (3 Supplier Sector) and three abstentions (3 Supplier Sector).

(Agenda Item 10.1) (66.67% Vote) ISO New England Operating Procedure No. 17, OP 17B, OP 17C

ACTION: APPROVED

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

Resolved, the Reliability Committee recommends Participants Committee support for revision of ISO New England Operating Procedure No. 17 – Load Power Factor Correction and OP 17B and OP 17C as distributed to the committee for the September 23, 2020 meeting, together with such other changes as discussed and agreed to at the meeting, and such other non-material changes as may be approved by the Chair and Vice-Chair of the Reliability Committee following the meeting.

The motion was then voted. Based on a voice vote, the motion passed with none opposed and no abstentions.

(Agenda Item 10.2) (66.67% Vote) ISO New England Operating Procedure No. 21

ACTION: APPROVED

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

Resolved, the Reliability Committee recommends Participants Committee support for revision of ISO New England Operating Procedure No. 21 – Emergency Inventory Accounting and Actions During and Energy Emergency as distributed to the committee for the September 23, 2020 meeting, together with such other changes as discussed and agreed to at the meeting, and such other non-material changes as may be approved by the Chair and Vice-Chair of the Reliability Committee following the meeting.

The motion was then voted. Based on a voice vote, the motion passed with none opposed and no abstentions.

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Sebastian Lombardi and Rosendo Garza, NEPOOL Counsel

DATE: September 23, 2020

RE: ISO-NE's Proposal to Exempt Energy Efficiency Resources from Pay-for-Performance Settlement

At the October 1, 2020 Participants Committee teleconference meeting, you will be asked to vote on proposed Tariff revisions to exempt energy efficiency resources in the Forward Capacity Market ("FCM") from Pay-for-Performance ("PFP") payments/penalties (the "Proposal"). A copy of the ISO's proposed Tariff revisions are provided with this memorandum. (*See* Attachment A.)

a. Market Rule Changes

Beginning at the June Markets Committee meeting, LS Power presented a proposal to change the Tariff provisions that were recently approved by NEPOOL in April[1] and accepted by the FERC in July[2] to: (1) remove energy efficiency capacity resources ("EE") from the PFP settlement rules (including removal from the "mutual insurance" system[3]); and (2) eliminate the current requirement that EE provide credit support from the FCM Delivery Financial Assurance.[4] LS Power's July presentation to the Markets Committee is included with this memorandum. (*See* Attachment B.)

On August 17, 2020, in response to requests by Participants, the ISO circulated a memorandum in which it stated that it would sponsor the LS Power proposal. The ISO explained, among other things, its view that the LS Power proposal would "treat [EE] resources in a manner that is consistent with their system benefits and contributions to resource adequacy."

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[1] Those changes were supported by NEPOOL as part of the April 2020 Consent Agenda, with two oppositions and two abstentions noted.

[2] Letter Order, *Energy Efficiency Treatment During Capacity Scarcity Conditions*, Docket No. ER20-1967-000, at 1 (July 21, 2020).

[3] *See* Section III.13.7.4(a), Allocation of Deficient or Excess Capacity Performance Payments (stating that "If the sum of all Capacity Performance Payments to all resources subject to the Capacity Scarcity Condition in the Capacity Zone in an Obligation Month is positive, the deficiency will be charged to resources in proportion to each such resource's Capacity Supply Obligation for the Obligation.").

[4] Lead Market Participants transacting in the FCM that are otherwise required to provide financial assurance under the ISO-NE Financial Assurance Policy are required to provide additional financial assurance as calculated by Section VII of the FAP.

The ISO further explained that it intended to file the proposal pursuant to Section 205 of the Federal Power Act. The ISO's memorandum together with the ISO's subsequent addendum to that memorandum, which provided details on additional non-substantive, clarifying Tariff changes incorporated by the ISO into the proposal, are included with this transmittal as Attachment C.

At its September 8, 2020 meeting, the Markets Committee considered the Market Rule changes to implement the Proposal and failed to recommend Participants Committee support for those changes, with a 55.57% Vote in favor (Market Rule changes require a 60% Vote for NEPOOL approval). A copy of the Notice of Actions of the Markets Committee detailing that September 8 vote is included with this memorandum as Attachment D.

If any Participant wishes to offer any amendment to the ISO's proposal to exempt EE from the PFP settlement rules, we urge you to contact NEPOOL Counsel (slombardi@daypitney.com or rgarza@daypitney.com) by close of business next Tuesday, September 29, so any such amendment can be circulated with the additional materials for the meeting that are going out that evening.

The following form of resolution can be used for Participants Committee action on the proposed Market Rule changes:

> 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 [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.

b. Financial Assurance Policy Changes

At its August 3, 2020 and August 21, 2020 meetings, the NEPOOL Budget and Finance Subcommittee (the "B&F Subcommittee") reviewed changes to the ISO New England Financial Assurance Policy ("FAP") that would support the implementation of the Proposal by excluding Capacity Supply Obligations associated with Energy Efficiency measures from the calculation of FCM Delivery Financial Assurance requirements. No one participating in the B&F Subcommittee meeting objected to the proposed changes to the FAP. A copy of the FAP changes, which require a 66.67% Vote to be supported by the Participants Committee, are included with this memorandum as Attachment E. The FAP and Market Rule changes are part of an integrated package and would advance together.

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

> 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 [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.

III.13.7.2.2 Calculation of Actual Capacity Provided During a Capacity Scarcity Condition.

* * *

(c) An On-Peak Demand Resource or Seasonal Peak Demand Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Actual Capacity Provided for each of its components, as determined below, where the MWhs of reduction, other than MWhs associated with Net Supply, are increased by average avoided peak transmission and distribution losses.

(i) For Energy Efficiency measures, ~~if the Capacity Scarcity Condition occurs during Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours, as applicable, then the Actual Capacity Provided shall be equal to the applicable reported monthly performance value; if the Capacity Scarcity Condition occurs in an interval outside of Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours, as applicable, then~~ the Actual Capacity Provided shall be zero.

(ii) For Distributed Generation measures submitting meter data for the full 24 hour calendar day during which the Capacity Scarcity Condition occurs, the Actual Capacity Provided shall be equal to the submitted meter data, adjusted as necessary for the five-minute interval in which the Capacity Scarcity Condition occurs.

(iii) For Load Management measures submitting meter data for the full 24 hour calendar day during which the Capacity Scarcity Condition occurs, the Actual Capacity Provided shall be equal to the submitted demand reduction data, adjusted as necessary for the five-minute interval in which the Capacity Scarcity Condition occurs.

(iv) Notwithstanding any other provision of this Section III.13.7.2.2(c), for any On-Peak Demand Resource or Seasonal Peak Demand Resource that fails to provide the data necessary for the ISO to determine the Actual Capacity Provided as described in this Section III.13.7.2.2(c), the Actual Capacity Provided shall be zero.

III.13.7.2.3 Capacity Balancing Ratio.

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate a Capacity Balancing Ratio using the following formula:

(Load + Reserve Requirement) / Total Capacity Supply Obligation

(a) If the Capacity Scarcity Condition is a result of a violation of the Minimum Total Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval~~;~~ (with ~~provided, however, that if the interval occurs outside of Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours, then~~ the Actual Capacity Provided of~~ any applicable~~ Energy Efficiency measures ~~shall be~~being zero, as specified in Section III.13.7.2.2(c)(i)).

Reserve Requirement = the Minimum Total Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval~~; provided, however, that if the interval occurs outside of Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours, then~~, excluding the Capacity Supply Obligations associated with ~~any applicable~~ Energy Efficiency measures~~ shall be excluded from the total amount of Capacity Supply Obligations, during the interval~~.

(b) If the Capacity Scarcity Condition is a result of a violation of the Ten-Minute Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval~~;~~ (with ~~provided, however, that if the interval occurs outside of Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours, then~~ the Actual Capacity Provided of ~~any applicable~~ Energy Efficiency measures ~~shall be~~being zero, as specified in Section III.13.7.2.2(c)(i)).

Reserve Requirement = the Ten-Minute Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval~~; provided, however, that if the interval occurs outside of Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours, then~~, excluding the Capacity Supply Obligations associated with ~~any applicable~~ Energy Efficiency measures~~ shall be excluded from the total amount of Capacity Supply Obligations, during the interval~~.

(c) If the Capacity Scarcity Condition is a result of a violation of the Zonal Reserve Requirement such that the associated Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the Capacity Zone during the interval plus the net amount of energy imported into the Capacity Zone from outside the New England Control Area during the interval (but not less than zero)~~;~~ (with ~~provided, however, that if the interval occurs outside of Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours, then~~ the Actual Capacity Provided of ~~any applicable~~ Energy Efficiency measures ~~shall be~~being zero, as specified in Section III.13.7.2.2(c)(i)).

Reserve Requirement = the Zonal Reserve Requirement minus any reserve support coming into the Capacity Zone over the internal transmission interface.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the Capacity Zone during the interval~~; provided however, that if the interval occurs outside of Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours, then~~, excluding the Capacity Supply Obligations associated with ~~any applicable~~ Energy Efficiency measures~~ shall be excluded from the total amount of Capacity Supply Obligations, during the interval~~.

(d) The following provisions shall be used to determine the applicable Capacity Balancing Ratio where more than one of the conditions described in subsections (a), (b), and (c) apply in a Capacity Zone.

(i) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Minimum Total Reserve Requirement and the Ten-Minute Reserve Requirement, but not the Zonal Reserve Requirement, the Capacity Balancing Ratio shall be calculated as described in Section III.13.7.2.3(a) for resources in that Capacity Zone.

(ii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Ten-Minute Reserve Requirement and the Zonal Reserve Requirement, but not the Minimum Total Reserve Requirement, the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(b) and the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(c).

(iii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with the Minimum Total Reserve Requirement and the Zonal Reserve Requirement (regardless of whether the Capacity Zone is also subject to Reserve Constraint Penalty Factor pricing associated with the Ten-Minute Reserve Requirement), the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(a) and the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(c).

III.13.7.2.4 Capacity Performance Score.

Each resource~~, other than one composed exclusively of Energy Efficiency measures~~, whether or not it has a Capacity Supply Obligation, will be assigned a Capacity Performance Score for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Score for the interval shall equal the resource's Actual Capacity Provided during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.13.7.2.2(c)(i)) minus the product of the resource's Capacity Supply Obligation (which for this purpose shall not be less than zero) and the applicable Capacity Balancing Ratio; provided, however, that for an On-Peak Demand Resource or a Seasonal Peak Demand Resource, (i) ~~if the Capacity Scarcity Condition occurs in an interval outside of Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours, as applicable, then~~ the ~~Actual Capacity Provided and~~ Capacity Supply Obligation associated with any ~~applicable~~ Energy Efficiency measures shall be excluded from the calculation of the resource's Capacity Performance Score; and (ii) for any Energy Efficiency, Load Management, or Distributed Generation measures reflected as a reduction in the load forecast as described in Section III.12.8 the Actual Capacity Provided and Capacity Supply Obligation shall be excluded from the calculation of the resource's Capacity Performance Score. The resulting Capacity Performance Score may be positive, zero, or negative.

III.13.7.4 Allocation of Deficient or Excess Capacity Performance Payments.

For each type of Capacity Scarcity Condition as described in Section III.13.7.2.1 and for each Capacity Zone, the ISO shall allocate deficient or excess Capacity Performance Payments as described in subsections (a) and (b) below. Where more than one type of Capacity Scarcity Condition applies, then the provisions below shall be applied in proportion to the duration of each type of Capacity Scarcity Condition.

(a) If the sum of all Capacity Performance Payments to all resources subject to the Capacity Scarcity Condition in the Capacity Zone in an Obligation Month is positive, the deficiency will be charged to resources in proportion to each such resource's Capacity Supply Obligation for the Obligation Month, excluding any resources subject to the stop-loss mechanism described in Section III.13.7.3 for the Obligation Month and excluding any resource, or portion thereof, consisting of Energy Efficiency measures. If the charge described in this Section III.13.7.4(a) causes a resource to reach the stop-loss limit described in Section III.13.7.3, then the stop-loss cap described in Section III.13.7.3 will be applied to that resource, and the remaining deficiency will be further allocated to other resources in the same manner as described in this Section III.13.7.4(a).

(b) If the sum of all Capacity Performance Payments to all resources subject to the Capacity Scarcity Condition in the Capacity Zone in an Obligation Month is negative, the excess will be credited to all such resources (excluding any resource, or portion thereof, consisting of Energy Efficiency measures) in proportion to each resource's Capacity Supply Obligation for the Obligation Month. For a resource subject to the stop-loss mechanism described in Section III.13.7.3 for the Obligation Month, any such credit shall be reduced (though not to less than zero) by the amount not charged to the resource as a result of the application of the stop-loss mechanism described in Section III.13.7.3, and the remaining excess will be further allocated to other resources in the same manner as described in this Section III.13.7.4(b)

Energy Efficiency's role in Pay-for-Performance

Presentation to the NEPOOL Markets Committee Stakeholders
July 14, 2020

Mark Spencer
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254-644-2352

Acronyms used in this Presentation

ACP	Actual Capacity Performance
CBR	Capacity Balancing Ratio
CMR	Current Market Rules
CSC	Capacity Scarcity Condition
CSO	Capacity Supply Obligation
DA	Day Ahead
DR	Demand Resource
EE	Energy Efficiency
FCM	Forward Capacity Market
LMP	Lead Market Participants
M&V	Measurement and Validation
PfP	Pay-for-Performance
RT	Real Time
RTOR	Real Time Operating Reserves

Presentation Outline

- Recap of June Presentation
- Settlement examples corrected
- EE funding
- Tariff Redlines
- Schedule

June 2020 NEPOOL Markets Committee Recap

Conclusions and Recommendations

- Conclusions:
    - CSCs are dynamic events / triggered by minimal reserve deficiencies;
    - A re-distribution of base FCM payments from all Resources. A key principle of PfP is to reward Resources' *actual* performance during a CSC;
    - Recommend the minimum criteria for Resources to participate in PfP should include:
        - (i) Being measured, and
        - (ii) being able to reduce load in the RT, provide energy in the RT, or provide reserves in the RT.
    - EE is not measured and does not participate in the RT (e.g., gen-line or line-line contingencies);
    - EE receives higher performance payments the lower system load is; and
    - There is a cost (i.e., posting of collateral) for all Resources to participate in PfP.
- Recommendations:
    - Retain EE's base capacity payments;
    - Remove EE from the PfP settlement including the "insurance pool"; and
    - Eliminate the requirement to provide credit support for the FCM Delivery Financial Assurance.

Examples to highlight the Redistribution Effect - Revisited

Actual and hypothetical examples

- Holding the 9/3/18 CSC event conditions constant except:
  - (a) changing the PfP rate to $5,455/MWh, and (b) applying DR On-Peak and Seasonal Peak Hours rules, EE would have received a **net payment of ~~$10.3~~ $13.1 million[1]** funded by charges to all non-EE CSO holders, a net reduction of ~~$0.31~~ $0.40/kW[1] in base capacity payments to all non-EE CSO holders; and
  - (a) changing the PfP rate to $5,455/MWh, (b) applying DR On-Peak and Seasonal Peak Hours rules, and (c) reducing system load by 10%, EE would have received a **net payment of ~~$12.6~~ $15.5 million[1]**, a net reduction of ~~$0.39~~ $0.48/kW[1] in base capacity payments to all non-EE CSO holders.
  - This increase in net payments to EE as system load decreases is in direct contradiction to the evidentiary record.
- Under this proposal net charges or net payments to EE in any hour of any CSC would be ZERO.
- The ISO provided the estimated settlement values from the event, the adjustments above were made from this original workbook and reviewed by ISO staff, and the detailed calculations have been included as an appendix to the slides.

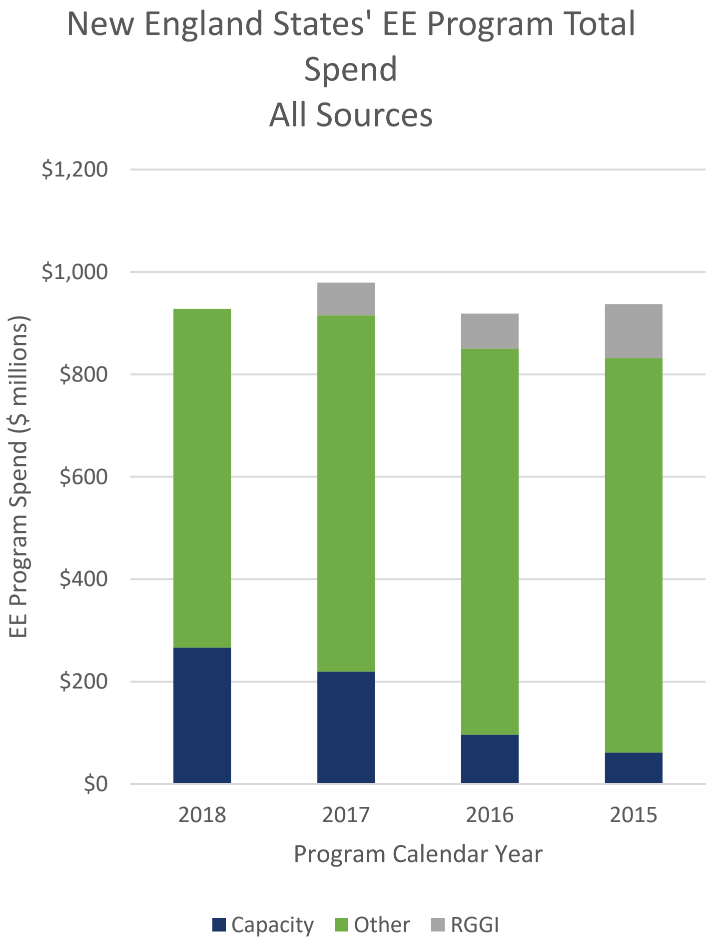
Notes:

1. June analysis failed to account for EE gross-up due to 8% T&D loss factor.

Energy Efficiency Funding Sources

Potential PfP performance payments represent a miniscule opportunity for EE

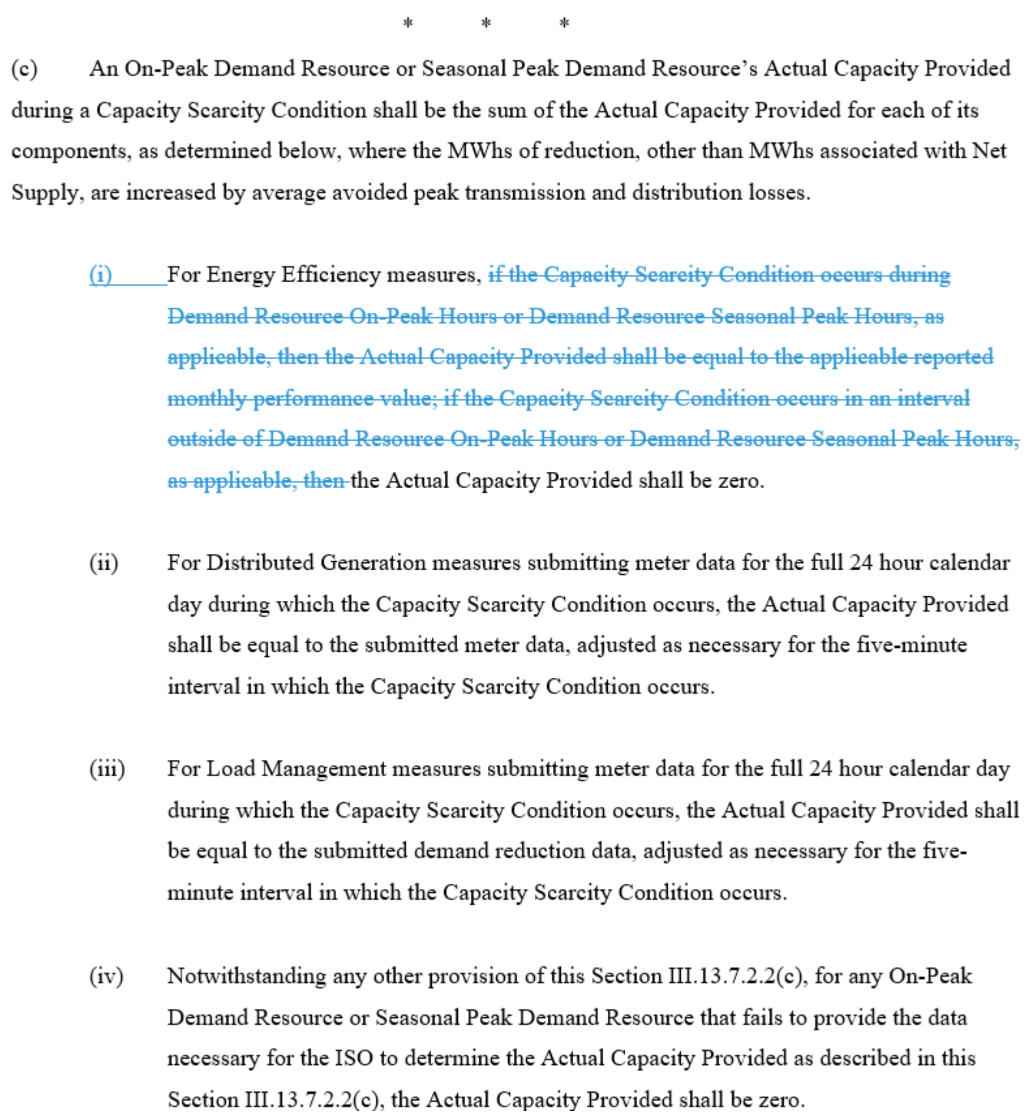
- The bulk of EE funding is derived from surcharges to retail customers (i.e., “other”) and a modest amount from RGGI revenues.
- The revenue streams from the capacity markets represent only 7-29% of the total funding streams.
- Long-run expectations of PfP performance payment contribution to total funding are likely less than <1%.



Sources: aceee.org and rggi.org

Proposed Tariff Changes – III.13.7.2.2

Redlined against ISO's filing in ER20-1967



III.13.7.2.2 Calculation of Actual Capacity Provided During a Capacity Scarcity Condition.

* * *

(c) An On-Peak Demand Resource or Seasonal Peak Demand Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Actual Capacity Provided for each of its components, as determined below, where the MWhs of reduction, other than MWhs associated with Net Supply, are increased by average avoided peak transmission and distribution losses.

(i) For Energy Efficiency measures, ~~if the Capacity Scarcity Condition occurs during Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours, as applicable, then the Actual Capacity Provided shall be equal to the applicable reported monthly performance value; if the Capacity Scarcity Condition occurs in an interval outside of Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours, as applicable, then~~ the Actual Capacity Provided shall be zero.

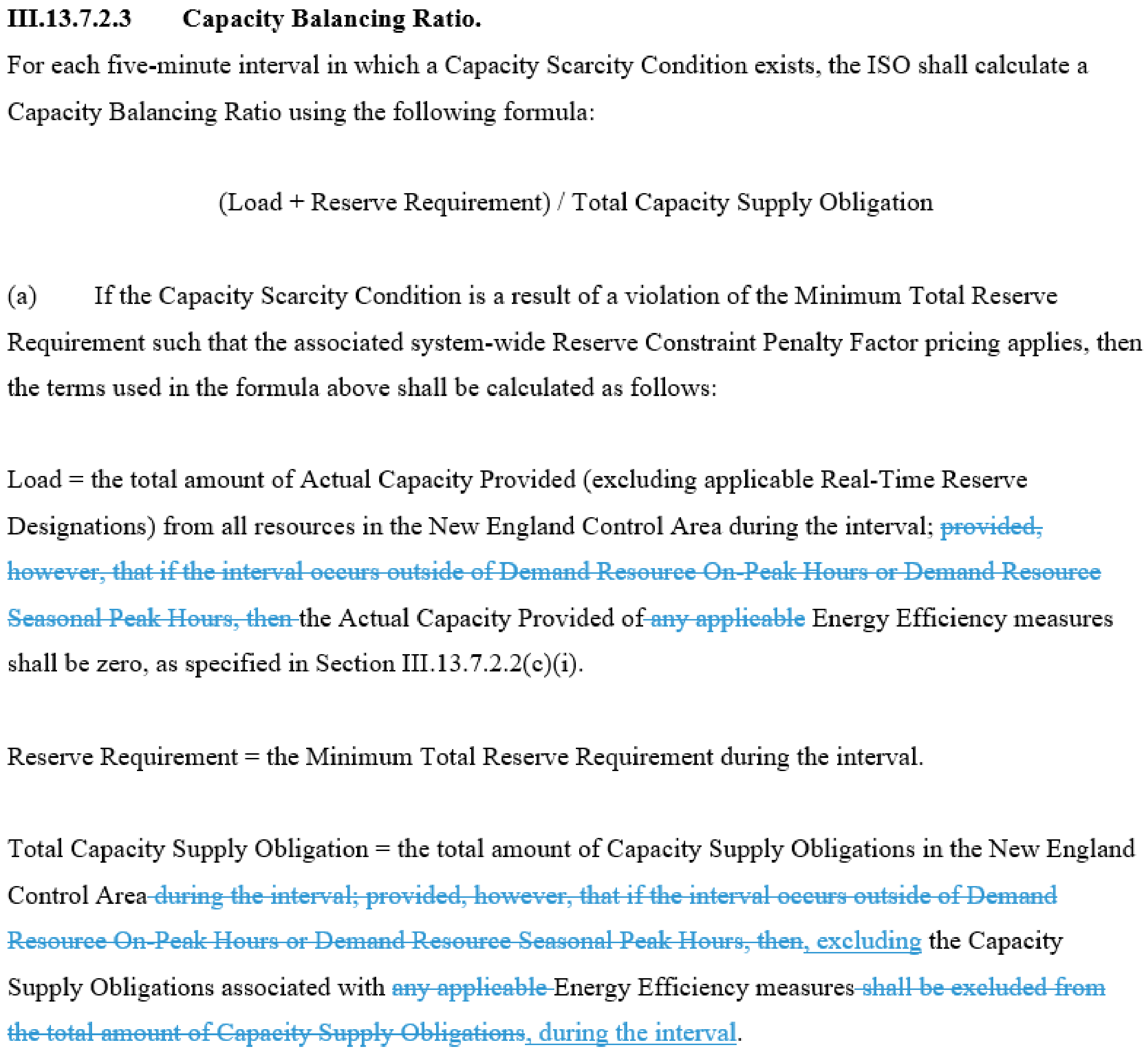
(ii) For Distributed Generation measures submitting meter data for the full 24 hour calendar day during which the Capacity Scarcity Condition occurs, the Actual Capacity Provided shall be equal to the submitted meter data, adjusted as necessary for the five-minute interval in which the Capacity Scarcity Condition occurs.

(iii) For Load Management measures submitting meter data for the full 24 hour calendar day during which the Capacity Scarcity Condition occurs, the Actual Capacity Provided shall be equal to the submitted demand reduction data, adjusted as necessary for the five-minute interval in which the Capacity Scarcity Condition occurs.

(iv) Notwithstanding any other provision of this Section III.13.7.2.2(c), for any On-Peak Demand Resource or Seasonal Peak Demand Resource that fails to provide the data necessary for the ISO to determine the Actual Capacity Provided as described in this Section III.13.7.2.2(c), the Actual Capacity Provided shall be zero.

Proposed Tariff Changes – III.13.7.2.3(a)

Redlined against ISO's filing in ER20-1967



III.13.7.2.3 Capacity Balancing Ratio.

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate a Capacity Balancing Ratio using the following formula:

(Load + Reserve Requirement) / Total Capacity Supply Obligation

(a) If the Capacity Scarcity Condition is a result of a violation of the Minimum Total Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

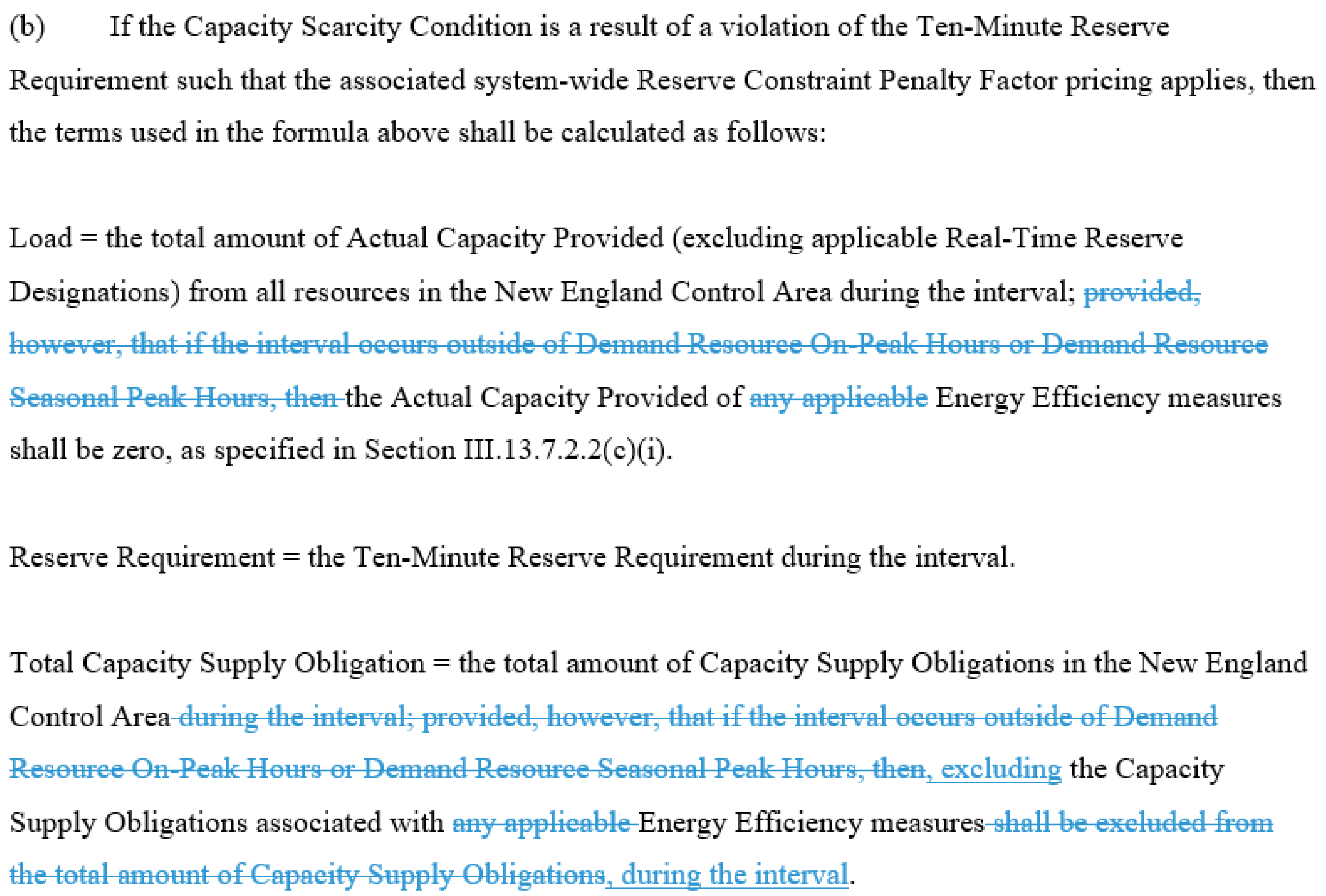
Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval; ~~provided, however, that if the interval occurs outside of Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours, then~~ the Actual Capacity Provided of ~~any applicable~~ Energy Efficiency measures shall be zero, as specified in Section III.13.7.2.2(c)(i).

Reserve Requirement = the Minimum Total Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area ~~during the interval; provided, however, that if the interval occurs outside of Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours, then~~, excluding the Capacity Supply Obligations associated with ~~any applicable~~ Energy Efficiency measures ~~shall be excluded from the total amount of Capacity Supply Obligations~~, during the interval.

Proposed Tariff Changes – III.13.7.2.3(b)

Redlined against ISO's filing in ER20-1967



(b) If the Capacity Scarcity Condition is a result of a violation of the Ten-Minute Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

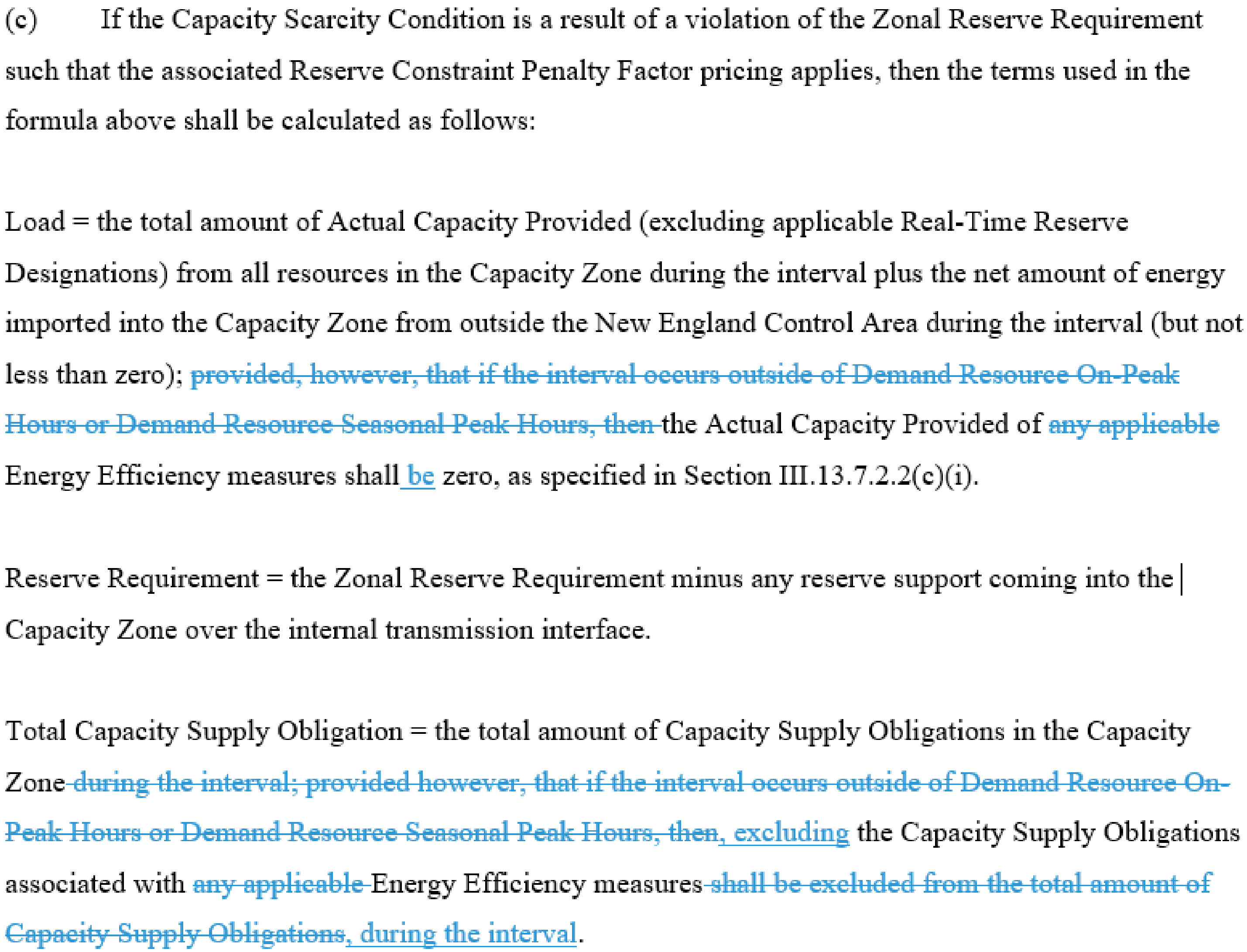
Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval; ~~provided, however, that if the interval occurs outside of Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours, then~~ the Actual Capacity Provided of ~~any applicable~~ Energy Efficiency measures shall be zero, as specified in Section III.13.7.2.2(c)(i).

Reserve Requirement = the Ten-Minute Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area ~~during the interval; provided, however, that if the interval occurs outside of Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours, then~~, excluding the Capacity Supply Obligations associated with ~~any applicable~~ Energy Efficiency measures ~~shall be excluded from the total amount of Capacity Supply Obligations~~, during the interval.

Proposed Tariff Changes – III.13.7.2.3(c)

Redlined against ISO's filing in ER20-1967



(c) If the Capacity Scarcity Condition is a result of a violation of the Zonal Reserve Requirement such that the associated Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

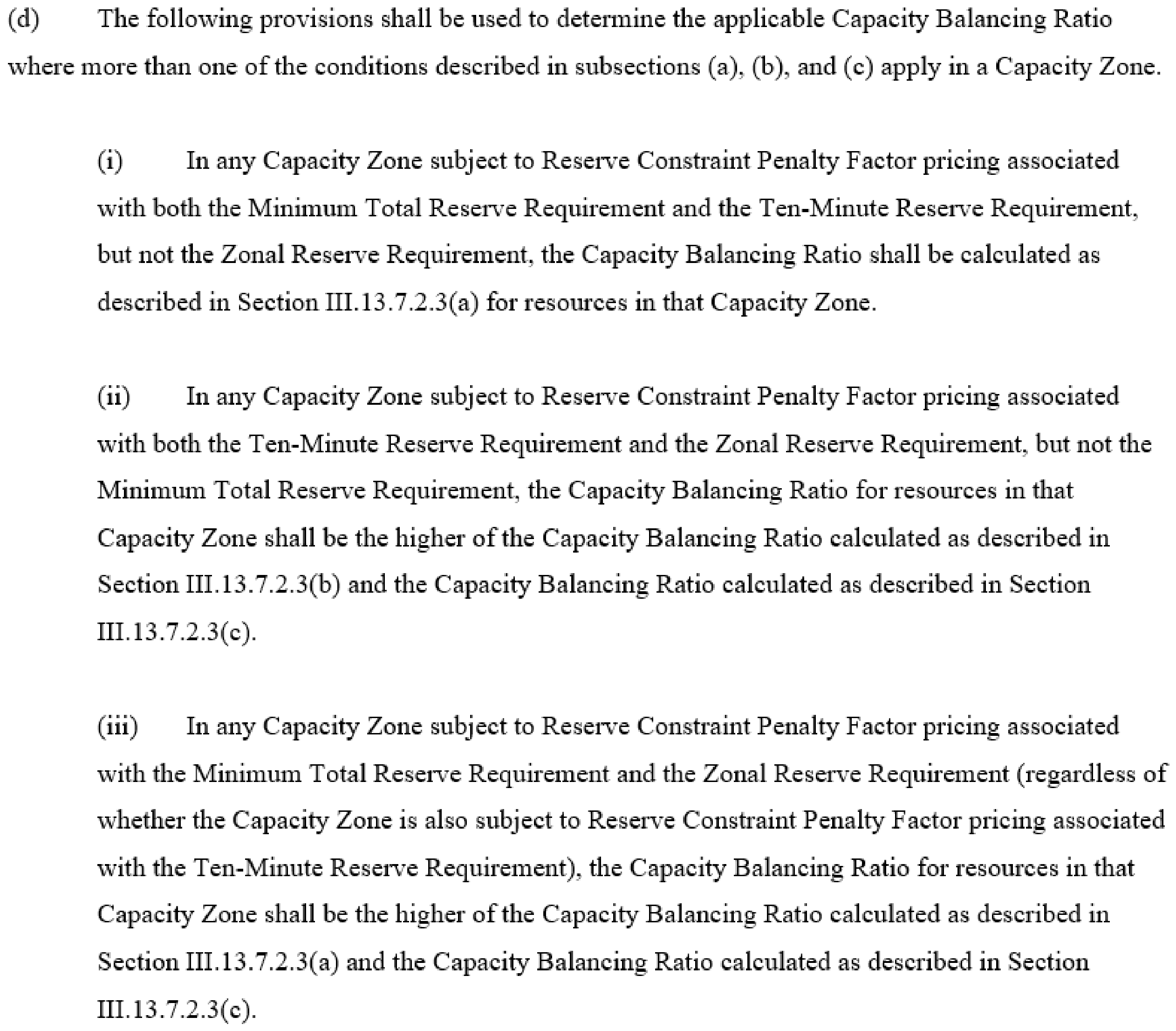
Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the Capacity Zone during the interval plus the net amount of energy imported into the Capacity Zone from outside the New England Control Area during the interval (but not less than zero); ~~provided, however, that if the interval occurs outside of Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours, then~~ the Actual Capacity Provided of ~~any applicable~~ Energy Efficiency measures shall be zero, as specified in Section III.13.7.2.2(c)(i).

Reserve Requirement = the Zonal Reserve Requirement minus any reserve support coming into the Capacity Zone over the internal transmission interface.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the Capacity Zone ~~during the interval; provided however, that if the interval occurs outside of Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours, then~~, excluding the Capacity Supply Obligations associated with ~~any applicable~~ Energy Efficiency measures ~~shall be excluded from the total amount of Capacity Supply Obligations~~, during the interval.

Proposed Tariff Changes – III.13.7.2.3(d)

Redlined against ISO's filing in ER20-1967



(d) The following provisions shall be used to determine the applicable Capacity Balancing Ratio where more than one of the conditions described in subsections (a), (b), and (c) apply in a Capacity Zone.

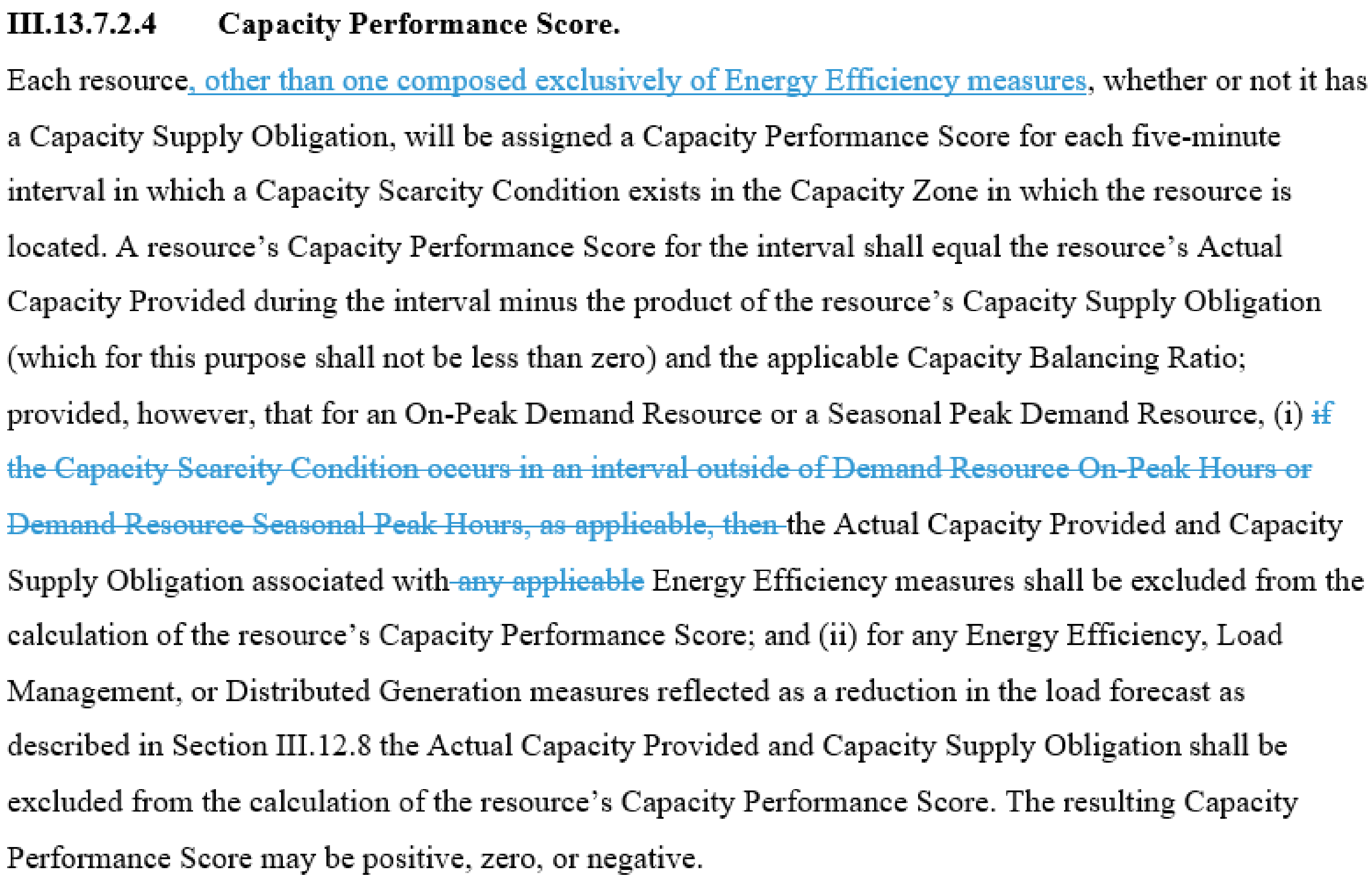
(i) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Minimum Total Reserve Requirement and the Ten-Minute Reserve Requirement, but not the Zonal Reserve Requirement, the Capacity Balancing Ratio shall be calculated as described in Section III.13.7.2.3(a) for resources in that Capacity Zone.

(ii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Ten-Minute Reserve Requirement and the Zonal Reserve Requirement, but not the Minimum Total Reserve Requirement, the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(b) and the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(c).

(iii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with the Minimum Total Reserve Requirement and the Zonal Reserve Requirement (regardless of whether the Capacity Zone is also subject to Reserve Constraint Penalty Factor pricing associated with the Ten-Minute Reserve Requirement), the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(a) and the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(c).

Proposed Tariff Changes – III.13.7.2.4

Redlined against ISO's filing in ER20-1967



III.13.7.2.4 Capacity Performance Score.

Each resource, other than one composed exclusively of Energy Efficiency measures, whether or not it has a Capacity Supply Obligation, will be assigned a Capacity Performance Score for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Score for the interval shall equal the resource's Actual Capacity Provided during the interval minus the product of the resource's Capacity Supply Obligation (which for this purpose shall not be less than zero) and the applicable Capacity Balancing Ratio; provided, however, that for an On-Peak Demand Resource or a Seasonal Peak Demand Resource, (i) ~~if the Capacity Scarcity Condition occurs in an interval outside of Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours, as applicable, then~~ the Actual Capacity Provided and Capacity Supply Obligation associated with ~~any applicable~~ Energy Efficiency measures shall be excluded from the calculation of the resource's Capacity Performance Score; and (ii) for any Energy Efficiency, Load Management, or Distributed Generation measures reflected as a reduction in the load forecast as described in Section III.12.8 the Actual Capacity Provided and Capacity Supply Obligation shall be excluded from the calculation of the resource's Capacity Performance Score. The resulting Capacity Performance Score may be positive, zero, or negative.

The Proposal and Schedule

- Market’s Committee schedule
  - 6/10: Introduce proposal and solicit stakeholder feedback
  - 7/14: Distribute Tariff changes and respond to stakeholder questions
  - 8/11: bring Tariff changes to the committee for a vote
- Budget & Finance Subcommittee:
  - 8/10: Introduce FAP changes and solicit stakeholder feedback
  - 8/21: Review FAP changes and respond to stakeholder questions
- Seek a vote on the Market Rule 1 and FAP changes at the 9/3 PC meeting.

Thank You for Your Time and Attention Today

Supporting Calculations – Base Case

Estimated settlement of September 3, 2018 event provided by ISO-NE

Current Rules	
Assumptions	**MW**
Energy Portion of $\text{ACP}_{\text{non-ee}}$	23,164
$\text{ACP}_{\text{ee, on-peak}}$	-
$\text{ACP}_{\text{ee, seasonal peak}}$	-
ACP_{ee}	-
Reserve Requirement (RR)	2,106
Non-EE CSO	32,543
EE CSO	2,458
Total CSO	35,001
System Load	23,164
System Reserves	1,804
Balancing Ratio (BR) *	0.722

* BR = (Energy Portion of $\text{ACP}_{\text{non-ee}}$ + ACP_{ee} + RR)/ Total CSO

PPR $ 5,333

Current Rules: PFP Settlement Example (Labor Day 2018)			
	Category	**Amount**	**Formula**
(a)	Charges to non-EE =	$ (125,308,665)	PPR × BR × Non-EE CSO
(b)	Charges to EE =	$ (9,464,668)	PPR x BR X EE CSO (This amount is not billed to EE for off-peak CSCs)
(c)	Payments to non-EE =	$ 133,162,667	PPR x ($\text{ACP}_{\text{non-ee}}$) = PPR x (System Load + System Reserves)
(d)	Payments to EE =	$ -	PPR x (ACP_{ee})
(e)	Difference in Charges and Payments	$ 1,610,667	PPR x Reserve Deficiency = –[(a) + (b)] – [(c) + (d)]
(f)	EE under-collection =	$ (9,464,668)	(b) (Charges not billed to EE due to the EE exemption are allocated through the BF)
(g)	Balancing Fund (BF) =	$ (7,854,002)	(e) + (f)
(h)	BF allocation to non-EE =	$ (7,302,442)	(g) x non-EE CSO/Total CSO
(i)	BF allocation to EE =	$ (551,560)	(g) x EE CSO/Total CSO
(j)	Final Settlement to non-EE =	$ 551,560	(a) + (c) + (h)
(k)	Final Settlement to EE =	$ (551,560)	(d) + (i)

Legend:

🟩 Key results

Supporting Calculations – Case #1

Base Case with Performance Payment Rate increased to $5,455/MWh

Current Rules	
Assumptions	**MW**
Energy Portion of $ACP_{non\text{-}ee}$	23,164
$ACP_{ee,\ on\text{-}peak}$	-
$ACP_{ee,\ seasonal\ peak}$	-
ACP_{ee}	-
Reserve Requirement (RR)	2,106
Non-EE CSO	32,543
EE CSO	2,458
Total CSO	35,001
System Load	23,164
System Reserves	1,804
Balancing Ratio (BR) *	0.722

Current Rules: PFP Settlement Example (Labor Day 2018)			
	Category	**Amount**	**Formula**
(a)	Charges to non-EE =	$ (341,779,384)	PPR × BR × Non-EE CSO
(b)	Charges to EE =	$ (25,814,883)	PPR x BR X EE CSO (This amount is not billed to EE for off-peak CSCs)
(c)	Payments to non-EE =	$ 363,201,173	PPR x ($ACP_{non\text{-}ee}$) = PPR x (System Load + System Reserves)
(d)	Payments to EE =	$ -	PPR x (ACP_{ee})
(e)	Difference in Charges and Payments	$ 4,393,093	PPR x Reserve Deficiency = –[(a) + (b)] – [(c) + (d)]
(f)	EE under-collection =	$ (25,814,883)	(b) (Charges not billed to EE due to the EE exemption are allocated through the BF)
(g)	Balancing Fund (BF) =	$ (21,421,789)	(e) + (f)
(h)	BF allocation to non-EE =	$ (19,917,411)	(g) x non-EE CSO/Total CSO
(i)	BF allocation to EE =	$ (1,504,379)	(g) x EE CSO/Total CSO
(j)	Final Settlement to non-EE =	$ 1,504,379	(a) + (c) + (h)
(k)	Final Settlement to EE =	$ (1,504,379)	(d) + (i)

* BR = (Energy Portion of $ACP_{non\text{-}ee}$ + ACP_{ee} + RR)/ Total CSO

PPR	$ 14,547

Legend:

🟦	Changed assumptions from base case
🟩	Key results

Supporting Calculations – Case #2

Base Case with (i) PPR increased to $5,455/MWh, and (ii) applying DR On-Peak and Seasonal Peak Hours rules

Current Rules	
Assumptions	**MW**
Energy Portion of $\text{ACP}_{\text{non-ee}}$	23,164
$\text{ACP}_{\text{ee, on-peak}}$	2,285
$\text{ACP}_{\text{ee, seasonal peak}}$	569
ACP_{ee}	2,854
Reserve Requirement (RR)	2,106
Non-EE CSO	32,543
EE CSO	2,458
Total CSO	35,001
System Load	23,164
System Reserves	1,804
Balancing Ratio (BR) *	0.804

* BR = (Energy Portion of $\text{ACP}_{\text{non-ee}}$ + ACP_{ee} + RR)/ Total CSO

PPR $ 14,547

Current Rules: PFP Settlement Example (Labor Day 2018)			
	Category	**Amount**	**Formula**
(a)	Charges to non-EE =	$ (380,385,983)	PPR × BR × Non-EE CSO
(b)	Charges to EE =	$ (28,730,871)	PPR x BR X EE CSO (This amount is not billed to EE for off-peak CSCs)
(c)	Payments to non-EE =	$ 363,201,173	PPR x ($\text{ACP}_{\text{non-ee}}$) = PPR x (System Load + System Reserves)
(d)	Payments to EE =	$ 41,522,587	PPR x (ACP_{ee})
(e)	Difference in Charges and Payments	$ 4,393,093	PPR x Reserve Deficiency = –[(a) + (b)] – [(c) + (d)]
(f)	EE under-collection =	$ -	(b) (Charges not billed to EE due to the EE exemption are allocated through the BF)
(g)	Balancing Fund (BF) =	$ 4,393,093	(e) + (f)
(h)	BF allocation to non-EE =	$ 4,084,581	(g) x non-EE CSO/Total CSO
(i)	BF allocation to EE =	$ 308,512	(g) x EE CSO/Total CSO
(j)	Final Settlement to non-EE =	$ (13,100,228)	(a) + (c) + (h)
(k)	Final Settlement to EE =	$ 13,100,228	(d) + (i)

Legend:

🟦	Changed assumptions from base case
🟩	Key results

Supporting Calculations – Case #3

Base Case with (i) PPR increased to $5,455/MWh, (ii) applying DR On-Peak and Seasonal Peak Hours rules, and (iii) reducing load by 10%

Current Rules	
Assumptions	**MW**
Energy Portion of $ACP_{non\text{-}ee}$	20,848
$ACP_{ee,\ on\text{-}peak}$	2,285
$ACP_{ee,\ seasonal\ peak}$	569
ACP_{ee}	2,854
Reserve Requirement (RR)	2,106
Non-EE CSO	32,543
EE CSO	2,458
Total CSO	35,001
System Load	20,848
System Reserves	1,804
Balancing Ratio (BR) *	0.737

* BR = (Energy Portion of $ACP_{non\text{-}ee}$ + ACP_{ee} + RR)/ Total CSO

PPR	$ 14,547

Current Rules: PFP Settlement Example (Labor Day 2018)			
	Category	**Amount**	**Formula**
(a)	Charges to non-EE =	$ (349,056,431)	PPR × BR × Non-EE CSO
(b)	Charges to EE =	$ (26,364,524)	PPR x BR X EE CSO (This amount is not billed to EE for off-peak CSCs)
(c)	Payments to non-EE =	$ 329,505,275	PPR x ($ACP_{non\text{-}ee}$) = PPR x (System Load + System Reserves)
(d)	Payments to EE =	$ 41,522,587	PPR x (ACP_{ee})
(e)	Difference in Charges and Payments	$ 4,393,093	PPR x Reserve Deficiency = –[(a) + (b)] – [(c) + (d)]
(f)	EE under-collection =	$ -	(b) (Charges not billed to EE due to the EE exemption are allocated through the BF)
(g)	Balancing Fund (BF) =	$ 4,393,093	(e) + (f)
(h)	BF allocation to non-EE =	$ 4,084,581	(g) x non-EE CSO/Total CSO
(i)	BF allocation to EE =	$ 308,512	(g) x EE CSO/Total CSO
(j)	Final Settlement to non-EE =	$ (15,466,575)	(a) + (c) + (h)
(k)	Final Settlement to EE =	$ 15,466,575	(d) + (i)

Legend:

🟦	Changed assumptions from base case
🟩	Key results

memo

To: NEPOOL Markets Committee and NEPOOL Budget and Finance Subcommittee

From: Henry Yoshimura, Director, Demand Resource Strategy, ISO New England

Date: August 17, 2020

Subject: **LS Power's Proposal Concerning Energy Efficiency and Capacity Performance Payments**

At the July 14, 2020 Markets Committee meeting, several participants asked the ISO to provide its perspective on the LS Power proposal regarding performance of energy efficiency resources in response to Capacity Scarcity Conditions and resulting Capacity Performance Payments. In considering the proposal and related discussion at the Markets Committee, we believe that implementing this proposal would improve the design of the Forward Capacity Market. Accordingly, ISO New England plans to sponsor this proposal in the stakeholder and regulatory processes going forward and to file the related Tariff changes under Section 205 of the Federal Power Act.

Our perspective is consistent with that expressed by the External Market Monitor at the July 14, 2020 Markets Committee meeting, as explained below. The proposal recognizes the characteristics of energy efficiency resources and proposes to treat them in a manner that is consistent with their system benefits. Like other resource types, energy efficiency resources help the region meet resource adequacy requirements. However, in contrast to other resource types, energy efficiency resources permanently reduce energy consumption. They deliver a comparable or improved level of end-use service immediately upon the installation of the energy efficiency measures, and they create a reduction of demand across all conditions and prices.

In order to serve the remaining load that appears in real-time, other resources, such as generation, imports, and demand response, are needed and also are acquired through the Forward Capacity Market. There is some amount of risk associated with the real-time performance of these other installed resources. For example:

- A generator or import may experience a forced outage.
- An operating reserve deficiency may occur when variable renewable resources are not available to produce energy.
- A battery's state of charge may be insufficient when needed in real-time for energy or reserves.
- A demand response asset may be unable to reduce energy consumption at a given moment.

Capacity Performance Payments are intended to provide resources with a strong incentive to perform by providing energy or reserves in real-time, which decreases the severity of Capacity Scarcity Conditions or avoids them altogether. Limiting Capacity Performance Payments to those resources whose performance could be at risk, unlike energy efficiency resources, accomplishes this design objective.[1]

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[1] Pursuant to the Commission's Order on Tariff Filing and Instituting Section 206 Proceeding, 147 FERC ¶ 61,172 at P 89 (issued May 30, 2014) (at https://www.iso-ne.com/static-assets/documents/regulatory/ferc/orders/2014/

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We recognize that the ISO and stakeholders worked many months in an extended stakeholder process to address an issue resulting from the ISO's implementation of the Commission-directed treatment of energy efficiency resources during off-peak hours. In an effort to implement the Commission's directive while avoiding "guaranteed negative Capacity Performance Payments during any Capacity Scarcity Condition during off-peak hours,"[2] many solutions were considered, including estimating energy efficiency performance during off-peak hours using "Shaping Option A." [3] This was a worthwhile endeavor, and the resulting solution addressed the settlement imbalances and related mutual insurance pool charges attributable to the ISO's implementation of the Commission's directive. The proposal discussed herein, however, treats energy efficiency resources in a manner that is consistent with their system benefits and contribution to resource adequacy. The ISO agrees with the removal of energy efficiency from Capacity Performance Payments for the reasons stated above.

The Tariff changes the ISO is planning to sponsor have been posted on the ISO website for your review and consideration. The proposed Tariff changes are identical to those proposed by LS Power at the July 14, 2020 Markets Committee meeting with just a few exceptions.

First, the ISO made some non-substantive, clarifying changes to Section III.13.7.2.4 (Capacity Performance Score). The incremental changes, which are relative to the version proposed at the July 14, 2020 Markets Committee meeting, are highlighted in yellow. Second, LS Power proposed that energy efficiency be removed "from the PfP settlement including the 'insurance pool'" – *see* second from last bullet, slide 4 of the July 14, 2020 LS Power presentation. Tariff redlines incorporating this component into Section III.13.7.4 (Allocation of Deficient or Excess Capacity Performance Payments) have been included in the ISO's package of Tariff changes and also are highlighted in yellow. While the Budget and Finance Subcommittee will not be discussing the proposed changes to the Section III.13 of the Tariff, the ISO has posted these changes with the Budget and Finance Subcommittee meeting materials for your reference.

Additionally, LS Power proposed that energy efficiency not be required "to provide credit support for the FCM Delivery Financial Assurance" – *id.*, last bullet, slide 4 of the July 14, 2020 LS Power presentation. Section VII.A of the ISO New England Financial Assurance Policy, which concerns FCM Delivery Financial Assurance, will be modified to reflect this design change. The NEPOOL Budget and Finance Subcommittee is reviewing these proposed changes at its August 21, 2020 meeting.[4] While the Markets Committee will not be voting on changes to the ISO New England Financial Assurance Policy, the ISO has posted these changes with the Markets Committee meeting materials for your reference.

Please contact me if you have any questions regarding this memo or the proposed Tariff changes. We look forward to the discussion of these changes at the August and September Budget and Finance

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may/er14_1050_000_5_30_14_pay_for_performance_order.pdf), energy efficiency resources are exempt from Capacity Performance Payments in non-measure hours, which comprise about 96% of the hours in a year.

[2] *Id.* at P 89.

[3] *See* https://www.iso-ne.com/static-assets/documents/2019/07/reportofthedrwgonassessingeerperformanceinallhours_final2.pdf.

[4] The Budget and Finance Subcommittee may hold an additional meeting in September 2020 to discuss further the proposed changes to the ISO New England Financial Assurance Policy.

Subcommittee meetings and during the September 2020 Markets Committee meeting where the technical committee vote will be requested.

memo

To: NEPOOL Markets Committee

From: Henry Yoshimura, Director, Demand Resource Strategy, ISO New England

Date: September 1, 2020

Subject: **Addendum to ISO New England August 17, 2020 Memo on Proposal Concerning Energy Efficiency and Capacity Performance Payments**

In its August 17, 2020 memo, the ISO provided its perspective on the participant proposal regarding performance of energy efficiency (EE) resources in response to Capacity Scarcity Conditions and resulting Capacity Performance Payments and its plan to sponsor the proposal going forward including an overview of the proposed Tariff changes since the July 14, 2020 Markets Committee meeting. This addendum provides details on several additional non-substantive, clarifying Tariff changes that have been incorporated into the proposal.

First, in Section III.13.7.2.3 of the Tariff (Capacity Balancing Ratio), the ISO has made several small changes for the sake of clarity; these changes are repeated in identical form in each of the section's three subsections.

Second, in the revisions previously proposed to Section III.13.7.2.4 of the Tariff (Capacity Performance Score) and posted for the July 14, 2020 Markets Committee meeting, resources composed exclusively of EE measures had been explicitly carved out such that they did not receive a Capacity Performance Score, rather than allowing their zero Actual Capacity Provided to flow into a Capacity Performance Score of zero. While the two descriptions reflect an identical implementation, a Tariff scheme in which resources composed exclusively of EE measures do not receive a Capacity Performance Score causes a number of complications for Tariff drafting, and would have required additional edits in other sections. As a result, the section is being updated such that a resource composed exclusively of EE measures will receive a Capacity Performance Score, which, by virtue of the Tariff mechanics, will be zero.

All incremental changes relative to the Tariff version posted for the July 14, 2020 Markets Committee meeting—both those described in the August 17 memo and those described in this addendum—are highlighted in yellow.

Please contact me if you have any questions regarding this addendum or the proposed Tariff changes.

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ISO new england

memo

To: Participants Committee

From: Erin Wasik-Gutierrez, Secretary, Markets Committee

Date: September 9, 2020

Subject: Actions of the Markets Committee – REVISION 1

This memo is notification to the Participants Committee of the following actions taken by the Markets Committee (MC) at its September 8-10, 2020 meeting. All sectors had a quorum.

1. (Agenda Item 1A) Meeting Minutes

ACTION: APPROVED

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

> RESOLVED, that the Markets Committee approves the minutes for the July 14-15, 2020 Markets Committee meeting, as circulated for the September 8-10 meeting, with such further non-substantive changes as the Chair and Vice-Chair may approve.

The motion was then voted. The motion passed unanimously based on a voice vote.

2. (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 to: (1) improve independent verifier ("Third Party Meter Reader") uploads; and (2) enable application programming interface ("API") access to the Account Holder public report.

3. (Agenda Item 4) Exempt Energy Efficiency from Pay for Performance Settlement

ACTION: MOTION FAILED ~~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 Market Rule 1 relating to the Exempt Energy Efficiency from Pay for Performance Settlement agenda item ~~Market Manual M-28 and Manual M-RPA relating to the Metering Requirements for DC Coupled Assets~~, 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. The motion failed to pass with a vote of 55.57% in favor. The individual Sector votes were Generation (13.92% in favor, 2.78% opposed, 0 abstentions), Transmission (16.70% in favor, 0.00% opposed, 0 abstentions), Supplier (16.70% in favor, 0.00% opposed, 2 abstentions), Publicly Owned Entity (0.00% in favor, 0.00~~16.70~~% opposed, 49 abstentions), Alternative Resources (8.25% in favor, 8.25% opposed, 3 abstentions), and End User (0.00% in favor, 16.70% opposed, 0 abstentions).

A. FCM Delivery Financial Assurance

A Designated FCM Participant must include, for the Capacity Supply Obligation of each resource in its portfolio other than the Capacity Supply Obligation associated with any Energy Efficiency measures, FCM Delivery Financial Assurance in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy. If a Designated FCM Participant's FCM Delivery Financial Assurance is negative, it will be used to reduce the Designated FCM Participant's Financial Assurance Obligations (excluding FTR Financial Assurance Requirements), but not to less than zero. FCM Delivery Financial Assurance is calculated according to the following formula:

FCM Delivery Financial Assurance = [DFAMW x PE x max[(ABR – CWAP), 0.1] x SF x DF] – MCC

Where:

MCC (monthly capacity charge) equals Monthly Capacity Payments incurred in previous months, but not yet billed. The MCC is estimated from the first day of the current delivery month until it is replaced by the actual settled MCC value when settlement is complete.

DFAMW (delivery financial assurance MW) equals the sum of the Capacity Supply Obligations of each resource in the Designated FCM Participant's portfolio for the month, excluding the Capacity Supply Obligation of any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1~~ and, during February through May and September through November, excluding the Capacity Supply Obligation associated with any Energy Efficiency measures~~. If the calculated DFAMW is less than zero, then the DFAMW will be set equal to zero.

PE (potential exposure) is a monthly value calculated for the Designated FCM Participant's portfolio as the difference between the Capacity Supply Obligation weighted average Forward Capacity Auction Starting Price and the Capacity Supply Obligation weighted average capacity price for the portfolio, excluding the Capacity Supply Obligation of any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1~~ and, during February through May and September through November, excluding the Capacity Supply Obligation associated with any Energy Efficiency measures~~. The Forward Capacity Auction Starting Price shall correspond to that used in the Forward Capacity Auction corresponding to the instant Capacity Commitment Period and the capacity prices shall correspond to those used in the calculation of the Capacity Base Payment for each Capacity Supply Obligation in the delivery month.

In the case of a resource subject to a multi-year Capacity Commitment Period election made in a Forward Capacity Auction prior to the ninth Forward Capacity Auction as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.1.2.7 of Market Rule 1, the Forward Capacity Auction Starting Price shall be replaced with the applicable Capacity Clearing Price (indexed for inflation) in the above calculation until the multi-year election period expires.

ABR (average balancing ratio) is the duration-weighted average of all of the system-wide Capacity Balancing Ratios calculated for each system-wide Capacity Scarcity Condition occurring in the relevant group of months in the three Capacity Commitment Periods immediately preceding the instant Capacity Commitment Period. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months. Until data exists to calculate this number, the temporary ABR for June through September shall equal 0.90; the temporary ABR for December through February shall equal 0.70; and the temporary ABR for all other months shall equal 0.60. As actual data becomes available for each relevant group of months, calculated values for the relevant group of months will replace the temporary ABR values after the end of each group of months each year until all three years reflect actual data.

CWAP (capacity weighted average performance) is the capacity weighted average performance of the Designated FCM Participant's portfolio. For each resource in the Designated FCM Participant's portfolio, excluding any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1~~ and, during February through May and September through November, excluding the Capacity Supply Obligation associated with any Energy Efficiency measures~~, and excluding from the remaining resources the resource having the largest Capacity Supply Obligation in the month, the resource's Capacity Supply Obligation shall be multiplied by the average performance of the resource. The CWAP shall be the sum of all such values, divided by the Designated FCM Participant's DFAMW. If the DFAMW is zero, then the CWAP is set equal to one.

The average performance of a resource is the Actual Capacity Provided during Capacity Scarcity Conditions divided by the product of the resource's Capacity Supply Obligation and the equivalent hours of Capacity Scarcity Conditions in the relevant group of months in the three Capacity Commitment Periods immediately preceding the instant Capacity Commitment Period. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months. Until data exists to calculate this number, the temporary average performance for gas-fired steam generating resources, combined-cycle combustion turbines and simple-cycle combustion turbines shall equal 0.90; the temporary average performance for coal-fired steam generating resources shall equal 0.85; the temporary average performance for oil-fired steam generating resources shall equal 0.65; the temporary average performance for all other resources shall equal 1.00. As actual data for each resource becomes available for each relevant group of months, calculated values for the relevant group of months will replace the temporary average performance values after the end of each group of months each year until all three years reflect actual data. The applicable temporary average performance value will be used for new and existing resources until actual performance data is available.

SF (scaling factor) is a month-specific multiplier, as follows:

June	2.000;
December and July	1.732;
January and August	1.414;
All other months	1.000.

DF(discount factor) is a multiplier that for the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, DF shall equal 0.75; and thereafter, DF shall equal 1.00.

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of September 29, 2020

The following activity, as more fully described in the attached litigation report, has occurred since the report dated September 1, 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

1	Remote ALJ Hearings (AD20-12)	Sep 23	"Remote Hearing Guidance for Participants" revised to make 3 changes

I. Complaints/Section 206 Proceedings

2	New England Generators' Exelon Complaint (EL20-67)	Sep 2-14	Eversource, MA AG, National Grid intervene
		Sep 14	Exelon answers Complaint; NESCOE, Public Systems and Connecticut Parties file comments supporting Complaint
		Sep 28	NEPGA answers Exelon's answer
3	206 Proceeding: FCM Pricing Rules Complaints Remand (EL20-54)	Sep 17	ESA intervenes (out-of-time)
		Sep 23	Reply Briefs filed by ISO-NE, BSW Project Co, MA AG, NEPGA, MA AG, CT PURA, PJM IMM, RENEW/ESA
4	Exelon PP-10 Complaint (EL20-52)	Sep 16	Exelon request rehearing of *Order Denying PP-10 Complaint*; FERC action required on or before Oct 16
5	206 Investigation Into ISO-NE Implementation of Order 1000 Exemptions for Immediate Need Reliability Projects (EL19-90)	Sep 29	FERC issues *Order 1000 Exemptions Allegheny Order* addressing arguments raised in requests for rehearing of the FERC's *Order Terminating Proceeding*

II. Rate, ICR, FCA, Cost Recovery Filings

9	Mystic 8/9 Cost of Service Agreement (ER18-1639)	Sep 17	FERC issues Notice of Denial by Operation of Law of the requests for rehearing of its *July 17 Orders*
	July 17 Orders	Sep 8-16	Mystic, MA AG, CT Parties, NESCOE appeal to the DC Circuit one or more of the *July 2018, Dec 2018, or July 17 Orders*
	ROE Paper Hearing	Sep 28	CT Parties, EMCOS, MA AG, and FERC Trial Staff file initial briefs presenting written evidence applying the FERC's *Opinion 569-A* ROE methodology to the facts of this proceeding; responses due ***Oct 28, 2020***
	Sep 2020 Compliance Filing	Sep 15	Mystic submits changes to COS Agreement in response to requirements of *July 17 Compliance Order*; comment date ***Oct 6, 2020***

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

* 10	Gross Load Forecast Reconstitution Revisions (ER20-2869)	Sep 11	ISO-NE and NEPOOL jointly file revisions; comment date ***Oct 2, 2020***
		Sep 14-29	Acadia Center, Calpine, Dominion, Eversource, Exelon, FirstLight, National Grid, NESCOE, NRDC/Sustainable FERC Project, NRG intervene
11	Information Policy §2.3 Revisions (ER20-2518)	Sep 17	FERC accepts revisions; eff. Oct 1, 2020
11	DAM Offer Window Modification (ER20-2511)	Sep 28	FERC accepts modification, eff. Sep 30, 2020

	11	Waiver Request: Settlement Only Resources Definition -- GMP's Searsburg facility (ER20-1755)	Sep 17	FERC denies requested waiver of definition of Settlement Only Resource for GMP's Searsburg facility
	12	*Order 841* Compliance Filings (Electric Storage in RTO/ISO Markets) (ER19-470)	Sep 10	FERC grants NEPOOL and ISO-NE request for a 35-day extension of time to comply with requirements in the *Order 841 Compliance Filing II Order;* compliance filing due ***Dec 7, 2020***

V. OATT Amendments / TOAs / Coordination Agreements

	17	CIP IROL Cost Recovery Rules (ER20-739)	Sep 17	FERC issues *CIP IROL Allegheny Order* addressing arguments raised by the IROL-Critical Facility Owners in their request for rehearing of the FERC's *CIP IROL Cost Recovery Order*
	17	*Order 845* Compliance Filing II (ER19-1951-002)	Sep 17	FERC accepts Jul 17, 2020 compliance filing, eff. Mar 19, 2020

V. Financial Assurance/Billing Policy Amendments

	17	FAP Enhancements and Clean-Up Changes (ER20-2145)	Sep 2	FERC accepts changes, eff. Sep 10, 2020

VI. Schedule 20/21/22/23 Changes

	18	Schedule 22: NSTAR/Vineyard Wind LGIA (ER20-2489)	Sep 17	FERC accepts LGIA, eff. Jul 10, 2020
	18	Schedule 21-NEP: DWW E&P Agreement (ER20-2454)	Sep 14	FERC accepts Agreement, eff. Jun 17, 2020

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

*	21	FCA14 Fuel Security Reliability Review Info Filing (ER18-2364)	Sep 25	ISO-NE files report assessing the study triggers, assumptions and scenarios used by ISO-NE in its FCA14 fuel security reliability review in comparison to actual conditions experienced during Winter 2019-20
*	21	ISO-NE Third Revised 2018 FERC Form 714 (not docketed)	Sep 3	ISO-NE submits third revision to 2018 FERC Form 714

IX. Membership Filings

	21	August 2020 Membership Filing (ER20-2581)	Sep 22	FERC accepts memberships of: Blueprint Power Technologies Inc. (Provisional Member); and Advanced Energy Economy Inc. (Fuels Industry Participant); and (ii) the termination of the Participant status of two End Users, New Hampshire Industries Inc. and TEC-RI

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

*	22	Cyber Planning for Response and Recovery Study (CYPRES) Report (not docketed)	Sep 14	FERC and NERC Staff publish a report on cyber planning for response and recovery that outlines best practices for the electric utility industry
	22	Joint Staff White Papers on Notices of Penalty for Violations of CIP Standards (AD19-18)	Sep 23	Joint Staffs issue Second White Paper; going forward, CIP non-compliance submissions will be filed and designated as CEII and NERC will no longer publicly post redacted versions of such submissions

	23	CIP Standards Development: Virtualization & Cloud Computing Services Projects (RD20-2)	Sep 17	NERC submits quarterly informational filing, reporting revised schedules (3-mo. delay) for Project 2016-02 (now targeted for a Mar 2022 filing) and Project 2019-02 (now targeted for a Mar 2021 filing)

XI. Misc. - of Regional Interest

*	25	203 Application: Millennium Power Partners (EC20-103)	Sep 18	Millennium requests authorization for transaction pursuant to which Beal Bank will acquire from Talen all of Millennium's membership interests; comment date ***Oct 9***
			Sep 24	Public Citizen intervenes
*	25	D&E Agreement: CL&P/UConn (ER20-2927)	Sep 21	CL&P files Agreement for D&E services related to UConn's increase of the real power capacity of the transmission service to its large generating facility; comment date ***Oct 9***
*	26	D&E Agrm't Cancellation: NSTAR/ Vineyward Wind (ER20-2915)	Sep 18	NSTAR submits notice of cancellation of D&E Agreement; comment date Oct 7
*	26	LGIA Cancellations: Superseded Great River Hydro LGIAs (Moore, Vernon, Comerford) (ER20-2897 et al.)	Sep 3	National Grid files notice of cancellation of LGIAs superseded by, and to become effective concurrently with the effectiveness of, new conforming LGIAs among ISO-NE, NEP and Great River Hydro
	26	Use Rights Transfer Agreement: NSTAR/HQUS (ER20-2724)	Sep 16	National Grid intervenes (out-of-time)
	27	D&E Agreement Cancellation: CL&P-NTE CT (ER20-2327)	Sep 3	FERC accepts notice of cancellation, eff. Jun 16, 2020

XII. Misc. - Administrative & Rulemaking Proceedings

	28	Carbon Pricing in RTO/ISO Markets Tech Conf (Sep 30, 2020) (AD20-14)	Sep 16	FERC issues third supplemental notice of tech conf.
	28	Hybrid Resources Tech Conf (Jul 23, 2020) (AD20-9)	Sep 23-28	Post-tech conf comments filed by ISO-NE, Enel, EEI, CAISO, MISO, NYISO, R Street, Savion, SEIA
	32	*Order 872*: Pricing and Eligibility Changes to PURPA Regulations (RM19-15)	Sep 17	FERC issues Notice of Denial by Operation of Law of requests for reh'g of *Order 872*, though it indicated that the requests would be addressed in a future order (which can be issued up until the record of the proceeding is filed with the Court of Appeals)
			Sep 18	SEIA petitions 9th Circuit for review of *Order 872*

XIII. Natural Gas Proceedings

	40	Iroquois ExC Project (CP20-48)	Sep 3, 18, 21	Iroquois further supplements application
			Sep 14	FERC issues data request regarding A&G Expenses
			Sep 21	Iroquois responds to Sep 14 data request

XIV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XV. Federal Courts

*	43	Mystic 8/9 Cost of Service Agreement (20-1343 et al. (consol.)	Sep 8	Mystic appeals *Mystic Orders*; Clerk issues order requiring appearances, docketing statement, procedural motions (if any), statement of issues to be filed by Oct 8; certified index to the record and dispositive motions by Oct 23
			Sep 16-18	NESCOE, MA AG, CT Parties also appeal certain of *Mystic Orders*; cases consolidated with 20-1343
	43	CASPR (20-1333)	Sep 2	Clerk issues order requiring appearances, docketing statement, procedural motions (if any), statement of issues to be filed by Oct 2; certified index to the record and dispositive motions by Oct 16
	43	2013/14 Winter Reliability Program Order on Compliance and Remand (20-1289, 20-1366) (consol.)	Sep 15	TransCanada again files appeal following FERC's Aug 27, 2020 Order Addressing Arguments Raised on Rehearing
			Sep 16	Cases consolidated; deadline for submission of certified index to the record extended to Oct 29, 2020
*	44	*Order 872* (20-72728) (9th Cir.)	Sep 17	SEIA petitions 9th Circuit for review of *Order 872*

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: September 29, 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 September 29, 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

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[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

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

On August 25, 2020, New England Generators[11] filed a complaint against Exelon[12] 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);

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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] "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.

[12] 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.").

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[13] and Connecticut Parties.[14] 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, are 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).

- **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")[15] (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.[16] 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***:[17]

(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, HQUS, LS Power, MA AG, MMWEC, National Grid, NESCOE, NHEC, NextEra, NRG, NTE Energy, Talen,

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

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

[15] *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)).

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

[17] 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.

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-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 September 16, 2020, Exelon requested of the FERC's order denying Constellation Mystic Power, LLC's ("Exelon") June 10, 2020 complaint ("PP-10 Complaint").[18] 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"),[19] 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.[20] 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,[21] 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."[22] In addition, the FERC found that the PP-10 Revisions did not violate the Attachment K provisions related to the *Order 1000* RFP process,[23] that Mystic failed to

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[18] *Constellation Mystic Power, LLC v. ISO New England Inc.*, 172 FERC ¶ 61,144 (Aug. 17, 2020), *reh'g requested* ("*Order Denying PP-10 Complaint*").

[19] 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).

[20] *Id.* at P 29.

[21] *Id.* at P 31.

[22] *Id.* at P 42.

[23] *Id.* at P 57.

demonstrate that ISO-NE violated its Tariff in conducting the Boston RFP process,[24] or that the PP-10 Revisions jeopardize reliability.[25]

Exelon requested rehearing of the *Order Denying PP-10 Complaint* on September 16, 2020. Exelon's request for rehearing is pending, with FERC action required on or before October 16, 2020, or the request will be deemed denied by operation of law. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Sophia Browning (202-218-3904; sbrowning@daypitney.com).

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

As previously reported, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration" on August 20, 2020.[26] The Notice confirmed that the 60-day period during which a petition for review of the FERC's *Order Terminating Proceeding*[27] can be filed with an appropriate federal court was triggered when the FERC did not act on the requests for rehearing (filed by CT PURA/CT OCC/MA AG ("CT/MA Parties"), LS Power and MMWEC/NHEC) of the *Order Terminating Proceeding*. On September 29, 2020, the FERC issued an order addressing arguments raised by those requests for rehearing.[28] As it is permitted under section 313(a) of the FPA[29] (since the record of this proceeding has not yet been filed in an appeal before a Federal Appeal Court), the FERC modified the discussion in the *Order Terminating Proceeding* but reached the same the result. Of note, the FERC "disagree[d] with the arguments raised on rehearing. In the June 2020 Order, the Commission found that there was insufficient evidence in the record to find under FPA section 206 that ISO-NE's implementation of the immediate need reliability project exemption was unjust, unreasonable, or unduly discriminatory or preferential … [or] inconsistent with or more expansive than the Commission directed. The arguments raised on rehearing have not persuaded us otherwise."[30] This matter has not, as of the date of this Report, been appealed to a Federal Court. If you have any questions concerning this proceeding, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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[24] *Id.* at P 58.

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

[26] *ISO New England Inc.*, 172 FERC ¶ 61,096 (Aug. 20, 2020).

[27] *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).

[28] *ISO New England Inc.*, 172 FERC ¶ 61,293 (Sep. 29, 2020) ("*Order 1000 Exemptions Allegheny Order*").

[29] 16 U.S.C. § 825l(a) (2020) ("Until the record in a proceeding shall have been filed in a court of appeals, as provided in subsection (b), the Commission may at any time, upon reasonable notice and in such manner as it shall deem proper, modify or set aside, in whole or in part, any finding or order made or issued by it under the provisions of this chapter.").

[30] *Order 1000 Exemptions Allegheny Order* at P 22.

- **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,[31] certified by Presiding ALJ Coffman to the Commission,[32] remains pending before the Commission.[33] 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,[34] 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*).[35] However, the FERC's orders were challenged, and in *Emera Maine,*[36] the DC Circuit vacated the FERC's prior orders, and remanded the case for further proceedings consistent with its order. The FERC's determinations in *Opinion 531* are thus no longer precedential, though the FERC remains free to re-adopt those determinations on remand as long as it provides a reasoned basis for doing so.

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[31] 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").

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

[33] 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.

[34] 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*")).

[35] *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*").

[36] *Emera Maine v. FERC*, 854 F.3d 9 (D.C. Cir. 2017) ("*Emera Maine*"). *Emera Maine* vacated the FERC's prior orders in the Base ROE Complaint I proceeding, and remanded the case for further proceedings consistent with its order. The Court agreed with both the TOs (that the FERC did not meet the Section 206 obligation to first find the existing rate unlawful before setting the new rate) and "Customers" (that the 10.57% ROE was not based on reasoned decision-making, and was a departure from past precedent of setting the ROE at the midpoint of the zone of reasonableness).

- ***Base ROE Complaints II & III (EL13-33 and EL14-86) (consolidated)***. The second (EL13-33)[37] and third (EL14-86)[38] 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.[39] 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[40] also went to hearing before an ALJ, Judge Glazer, who issued his initial decision on March 27, 2017.[41] 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.[42] 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.[43] The FERC indicated its intention that the methodology be its policy going forward, including in the four currently pending New England proceedings (*see*, however, *Opinion 569-A*[44] (EL14-12; EL15-45) in

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[37] 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%.

[38] 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.

[39] *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*").

[40] 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.

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

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

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

[44] *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

Section XI below). The FERC established a paper hearing on how its proposed methodology should apply to the four pending ROE proceedings.[45]

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%.[46] 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[47] for an extension of time to submit briefs, the latest date for filing initial and reply briefs was extended to January 11 and March 8, 2019, respectively. On January 11, initial briefs were filed by EMCOS, Complainant-Aligned Parties, TOs, EEI, Louisiana PSC, Southern California Edison, and AEP. As part of their initial briefs, each of the Louisiana PSC, SEC and AEP also moved to intervene out-of-time. Those interventions were opposed by the TOs on January 24. The Louisiana PSC answered the TOs' January 24 motion on February 12. Reply briefs were due March 8, 2019 and were submitted by the TOs, Complainant-Aligned Parties, EMCOS, FERC Trial Staff.

Opinion 569; and (iv) calculating the zone of reasonableness in equal thirds, instead of using the quartile approach that was applied in *Opinion 569*.

[45] *Id.* at P 19.

[46] *Id.* at P 59.

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

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*[48] and requested that the FERC re-open the record to permit that additional testimony on the impacts of the *MISO ROE Order*'s changes. On January 21, EMCOS and CAPs opposed the TOs' request and brief.

These matters 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

- **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")[49] among Constellation Mystic Power ("Mystic"), Exelon Generation Company ("ExGen") and ISO-NE, which is to provide compensation for the continued operation of the Mystic 8 & 9 units from June 1, 2022 through May 31, 2024.

July 17 Orders. The *July 17 Orders* addressed (i) requests for rehearing of the *July 2018 Order*[50] (the FERC's initial order in this proceeding, accepting the COS Agreement but suspending its effectiveness and setting the matter for accelerated hearings and settlement discussions); (ii) *Dec 2018 Order*[51] (the FERC's order following hearings ordered in the *July 2018 Order* conditionally accepting the COS Agreement, subject to a compliance filing modifying aspects of the COS Agreement that FERC rejected or directed be changed, and establishing a paper hearing to ascertain whether and how the ROE methodology that FERC proposed in *Coakley* should apply in this case); and (iii) the Mar 2019 Compliance Filing[52] (submitted in response to the requirements of the *Dec 2018 Order*).

Requests for rehearing and/or clarification of one or more of the *July 17 Orders* were filed by ISO-NE (the *Dec 2018 Rehearing Order*),[53] CT Parties[54] (the *Dec 2018 Rehearing Order* and on the Mar 2019

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[48] *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).

[49] 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.

[50] *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*").

[51] *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*"). The *Dec 2018* Rehearing *Order* set aside the parts of the *Dec 2018 Order* that required the COS Agreement to include a sliding scale or other revenue crediting mechanism and the part that required Mystic to true-up revenues, granted clarification requested by Mystic that the FERC did not intend to re-state its prudence standard in the *Dec 2018 Order*, and denying clarifications requested by Mystic, NESCOE and ENECOS.

[52] *Constellation Mystic Power, LLC*, 172 FERC ¶ 61,045 (July 17, 2020) ("*July 17 Compliance Order*") (order on compliance and directing further compliance).

[53] ISO-NE seeks rehearing of the FERC's finding that the Tank Congestion Charge will no longer be applied in the determination of Mystic's fuel costs.

[54] "CT Parties" for purposes of this proceeding are CT PURA, CT DEEP and the CT OCC.

Compliance Filing), NESCOE (the *Dec 2018 Rehearing Order*), and NEPGA (each of the *July 17 Orders*). The FERC did not take action on those requests. On September 17, 2020, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[55] 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 the requests for rehearing of the *July 17 Orders*. The Notice also indicated that the FERC would address, as is its right, the rehearing requests in a future order, and may modify or set aside its orders, in whole or in part, "in such manner as it shall deem proper." That order must be issued by the date that the record of the proceeding must be filed with the court of appeals.[56]

As noted in Section XV below, each of the *July 17 Orders* (and the earlier, underlying orders) have been appealed to the DC Circuit: by Mystic (*Dec 2018 Order* and the *Dec 2018 Rehearing Order);* MA AG (*July 2018 Order*, *July 2018 Rehearing Order, Dec 2018 Order,* the *Dec 2018 Rehearing Order*); CT Parties I (*Dec 2018 Order,* February 15, 2019 Tolling Order, the *Dec 2018 Rehearing Order)*; CT Parties II (*July 17 Compliance Order*), and NESCOE (*Dec 2018 Order,* the *Dec 2018 Rehearing Order*).

ROE Paper Hearings. 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,[57] 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 are due on or before October 28, 2020.

Sep 2020 Compliance Filing. 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 are due on or before October 6, 2020.

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 September 11, 2020, ISO-NE and NEPOOL jointly filed changes (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"). The Gross Load Forecast Reconstitution Revisions were supported by the Participants Committee at its September 3, 2020 meeting (Agenda Item #7). A November 10, 2020 effective date was requested. Comments on this filing are due on or before October 2, 2020. Thus far, doc-less interventions have been filed by Acadia Center, Calpine, Dominion,

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[55] *ISO New England Inc.*, 172 FERC ¶ 62,149 (Sep. 17, 2020).

[56] *See* 16 USC § 825l(a) ("Until the record in a proceeding shall have been filed in a court of appeals, … the [FERC] may at any time, upon reasonable notice and in such manner as it shall deem proper, modify or set aside, in whole or in part, any finding or order made or issued by it under the provisions of this chapter.").

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

Eversource, Exelon, FirstLight, National Grid, NESCOE, NRD/Sustainable FERC Project, and NRG. If you have any questions concerning this proceeding, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Information Policy §2.3 Revisions (ER20-2518)**

On September 17, 2020, the FERC accepted revisions to Section 2.3 of the Information Policy filed jointly by ISO-NE and NEPOOL.[58] As previously reported, the revisions are designed (i) to improve and clarify communications with Participants regarding the status of Participants emerging from bankruptcy and (ii) to provide ISO-NE with greater flexibility when disclosing confidential information of defaulting Participants to the FERC, courts of competent jurisdiction (esp. bankruptcy courts), and/or other agencies. The revisions do not modify the type of information that will be disclosed on weekly notices and do not affect the confidentiality and non-disclosure obligations of Participants under the Information Policy. The revisions were accepted effective as of October 1, 2020, as requested. Unless the September 17 order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **DAM Offer Window Modification (ER20-2511)**

On September 28, 2020, the FERC accepted revisions to Market Rule 1 Section 1.10.1A to extend by 30 minutes the Day-Ahead Energy Market ("DAM") offer window jointly filed by ISO-NE and NEPOOL.[59] Also included with the DAM Offer Window modification were two Offer Cap clean-up changes, one to add Demand Reduction Offers to the consolidated offer floor provisions of Section III.1.9.1.2, the other to remove "Energy Offer Cap" from Section III.1.10.1A(e)(ii). The revisions were accepted effective September 30, 2020, as requested. Unless the September 28 order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **Waiver Request: Settlement Only Resources Definition -- GMP's Searsburg facility (ER20-1755)**

On September 17, 2020, the FERC denied Green Mountain Power ("GMP")'s May 4, 2020 request for a limited waiver from the revised definition of Settlement Only Resources[60] as applied to GMP's Searsburg wind power facility.[61] In denying the request, the FERC found that GMP's request did not satisfy the FERC's criteria for the granting of waiver of tariff provisions.[62] Specifically, the GMP request failed to demonstrate that its waiver was limited in scope or that it would not have undesirable consequences.[63] Unless the *Order Denying Searsburg Waiver* is challenged, with any challenges due on or before October 19, 2020, this proceeding will be concluded. If

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[58] *ISO New England Inc. and the New England Power Pool Participants Comm.*, Docket No. ER20-2518 (Sep. 17, 2020) (unpublished letter order).

[59] *ISO New England Inc. and New England Power Pool Participants Comm.*, Docket No. ER20-2511 (Sep. 28, 2020) (unpublished letter order).

[60] As of January 1, 2021, Settlement Only Resources will be "generators of less than 5 MW of maximum net output when operating at any temperature at or above zero degrees Fahrenheit, that meet the metering, interconnection and other requirements in or otherwise eligible for Settlement Only Resource treatment as described in ISO New England Operating Procedure No. 14 and that have elected Settlement Only Resource treatment as described in the ISO New England Manual for Registration and Performance Auditing." As previously reported, the Searsburg facility has a nameplate rating of 6 MW (11 Zond Z-40 turbines, each of which is rated at 550 kW). Searsburg's SCADA system does not have the ability to set an active power limit for the wind facility, the GMP control room does not have any turbine-level control capability, and GMP is unable to acquire turbine software capable of allowing Searsburg to set up an active power limit.

[61] *Green Mountain Power Corp.*, 172 FERC ¶ 61,250 (Sep. 17, 2020) ("*Order Denying Searsburg Waiver*").

[62] The FERC has granted waiver of tariff provisions where it meet each of the following four criteria: (1) the applicant acted 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. *See, e.g.*, *Midcontinent Indep. Sys. Operator, Inc.*, 154 FERC ¶ 61,059, at P 13 (2016).

[63] *Order Denying Searsburg Waiver* at PP 12-13 (finding the Waiver not limited in scope (for failure to identify a specific and limited period of time) and the small size of the facility insufficient in and of itself to establish that there would be no undesirable consequences).

you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

This proceeding was initiated by ISO-NE's April 15, 2020 filing of Tariff revisions to incorporate comprehensive, long-term market enhancements to address the fuel security challenges facing the New England region ("Energy Security Improvements" or "ESI").[64] The revisions included NEPOOL-supported alternatives to certain aspects of the enhancements proposed by ISO-NE, which ISO-NE and NEPOOL agreed would be considered on equal legal footing with ISO-NE's favored alternative. ISO-NE asked that the FERC issue an order and accept the changes effective no later than November 1, 2020, conditioned on ISO-NE's filing of an appropriate market power mitigation proposal supported by a Market Power Assessment by the fourth quarter of 2021. The ESI Proposals were considered at the April 2 Participants Committee meeting. ISO-NE's ESI proposal with three amendments proposed by NESCOE was approved by NEPOOL and is the NEPOOL Alternative. ISO-NE's ESI proposal without the amendments (the "ISO-NE Proposal") was not supported. Comments on this filing are due on or before May 15, 2020. On April 24, NEPOOL submitted comments to provide NEPOOL's support for the NEPOOL Alternative.

Comments and protests were filed by Avangrid, API, Calpine/Vistra, Cogentrix, Dominion, Excelerate, Exelon, FirstLight, IECG, MA AG/NH OCA, MMWEC, NECOES/ENE, NESCOE, Repsol, NEPGA, NRG, PIOs, ISO-NE IMM, Potomac Economics, CT DEEP, MPUC, VT PUC, AEE, EPSA, National Hydropower Assoc., and the National Gas Supply Association ("NGSA"). On June 1 NEPOOL and NESCOE filed answers to some of the pleadings submitted. Doc-less interventions were filed by Acadia Center, Brookfield RTM, CT OCC, CT AG, CLF, ENE, Environmental Defense Fund, Eversource, National Grid, NextEra, NRDC/Sustainable FERC Project, PSEG, Repsol, Shell, UCS, Vistra, AWEA, APPA, EPSA, Helix Maine, Public Citizen, Sierra Club, and Vote Solar. On June 5, Calpine/Vistra and NEPGA answered NESCOE's May 15 protest. On June 10, FirstLight answered NEPOOL's and NESCOE's answers. ISO-NE submitted its answer to various pleadings on June 16. On June 22, NESCOE filed a second answer, to the June 5 answers by NEPGA and Calpine/Vistra. NESCOE, and the MA AG answered ISO-NE's Jun 16 answer on June 30, And, finally, NEPOOL answered ISO-NE's out-of-time answer on July 1.

There has been no activity in this proceeding since the last Report and this matter remains 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).

- ***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[65] and February 10, 2020[66] *Order 841*[67] 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;

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[64] This 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*").

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

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

[67] *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*").

and (ii) applying transmission charges to electric storage resources when they are not being dispatched to provide one of those tariff-defined services.[68]

- ***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 meeting (following completion of Markets Committee consideration). 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*[69] remain pending before the FERC. As previously reported, the *Fuel Security Retention Proposal Order* accepted ISO-NE's Proposal[70] 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,

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

[69] *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.

[70] 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").

MPUC, and PIOs.[71] 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[72] that (i) denied ISO-NE's request for waiver of certain Tariff provisions that would have permitted ISO-NE to retain Mystic 8 & 9 for fuel security purposes (ER18-1509); and (ii) instituted an FPA Section 206 proceeding (EL18-182) (having preliminarily found that the ISO-NE Tariff may be unjust and unreasonable in that it fails to address specific regional fuel security concerns identified in the record that could result in reliability violations as soon as year 2022). The *Mystic Waiver Order* required ISO-NE, on or before August 31, 2018 to either: (a) submit interim Tariff revisions that provide for the filing of a short-term, cost-of-service agreement ("COS Agreement") to address demonstrated fuel security concerns (and to submit by July 1, 2019 permanent Tariff revisions reflecting improvements to its market design to better address regional fuel security concerns "Chapter 3 Proposal"); or (b) show cause as to why the Tariff remains just and reasonable in the short- and long-term such that one or both of Tariff revisions filings is not necessary.

Addressing the waiver element, the FERC found the waiver request "an inappropriate vehicle for allowing Mystic 8 and 9 to submit a [COS Agreement] in response to the identified fuel security need" and further that the request "would not only suspend tariff provisions but also alter the existing conditions upon which a market participant could enter into a [COS Agreement] (for a transmission constraint that impacts reliability) and allow for an entirely new basis (for fuel security concerns that impact reliability) to enter into such an agreement." The FERC concluded that "[s]uch new processes may not be effectuated by a waiver of the ISO-NE Tariff; they must be filed as proposed tariff provisions under FPA section 205(d)."[73] 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."[74]

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).[75] 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.[76] 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[77] and an *ex ante* cost allocation proposal that appropriately identifies beneficiaries and adheres to FERC cost causation precedent.[78]

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

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

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

[73] *Id.* at P 47.

[74] *Id.* at P 48.

[75] *Id.* at P 55.

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

[77] *Id.* at P 57.

[78] *Id.* at P 58.

- ***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***[79] (requesting that the FERC clarify that (i) the discussion in the *Mystic Waiver Order* of pricing treatment in the FCM for fuel security reliability resources is not a final determination nor is it intended to establish FERC policy; (ii) the FERC did not intend to prejudge whether entering those resources in the FCM as price takers would be just and reasonable; and (iii) that ISO-NE may confirm its submitted position that price taking treatment for these resources would, in fact, be a just and reasonable outcome. Failing such clarification, Connecticut Parties request rehearing, asserting that the record fails to support a determination that resources retained for reliability to address fuel security concerns must be entered into the FCM at a price greater than zero);
- ***ENECOS*** (asserting that the *Mystic Waiver Order* (i) misplaces reliance on ISO-NE "assertions concerning 'fuel security,' which do not in fact establish a basis in evidence or logic for initiating" a Section 206(a) proceeding; (ii) impermissibly relies on extra-record material that the FERC did not actually review and that intervenors were afforded no meaningful opportunity to challenge; and (iii) speculation concerning potential future modifications to the FCM bidding rules as to retiring generation retained for fuel security misunderstands the problem it seeks to address, and prejudices the already truncated opportunities for stakeholder input in this proceeding), ENECOS suggest that the FERC should grant rehearing, vacate its show cause directive, strike its dictum concerning potential treatment of FCM bidding for retiring generation retained for "fuel security," and direct ISO-NE to proceed either in accordance with its Tariff or under FPA Section 205 to address, with appropriate evidentiary support, whatever concerns it believes to exist concerning "fuel security");
- ***MA AG*** (asserting that the decision to institute a Section 206 proceeding was insufficiently supported by sole reliance on highly contested OFSA and Mystic Retirement Studies; and the FERC should reconsider the timeline for the permanent tariff solution and set the deadline for implementation no later than February 2020);
- ***MPUC*** (challenging the Order's (i) adoption of ISO-NE's methodology and assumptions in the OFSA and Mystic Retirement Studies without undertaking any independent analysis; (ii) failure to address arguments and analysis challenging assumptions in the OFSA and Mystic Retirement Studies; (iii) failure to address the MPUC argument that the Mystic Retirement Studies adopted a completely new standard for determining a reliability problem three years in advance; (iv) unreasonably discounting of the ability of Pay-for-Performance to provide sufficient incentives to Market Participants to ensure their performance under stressed system conditions; and (v) failure to direct ISO-NE to undertake a Transmission Security Analysis consistent with the provisions in the Tariff);
- ***New England EDCs***[80] (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***[81] (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

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

[80] 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).

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

- ♦ ***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).

- **CASPR (ER18-619)**

On August 31, 2020, Sierra Club, NRDC, RENEW, and CLF petitioned the DC Circuit Court of Appeals for review of the *CASPR Order*.[82] As previously reported, the FERC had issued a May 7, 2018 tolling order to afford it additional time to consider, but has never issued an order on, the requests for rehearing of the *CASPR Order* filed by (i) ***NextEra/NRG*** (challenging the RTR Exemption Phase Out); (ii) ***ENECOS***[83] (challenging the FERC's findings with respect to the definition of Sponsored Policy Resource and the allocation of CASPR side payment costs to municipal utilities); (iii) ***Clean Energy Advocates***[84] (challenging the CASPR construct in its entirety, asserting that state-sponsored resources should not be subject to the MOPR); and (iv) ***Public Citizen*** (also challenged the CASPR construct in its entirety and the *CASPR Order*'s failure to define "investor confidence"). In light of the DC Circuit's *Allegheny* decision, which recently held that tolling orders "are not the kind of action on a rehearing application that can fend off a deemed denial and the opportunity for judicial review", and the August 31 appeal, this matter has now moved on to the DC Circuit. Absent any further FERC activity prior to the filing of the record in the DC Circuit proceeding,[85] reporting on this matter will move to Section XV in future Reports. If you have any questions concerning this proceeding, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

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

[83] The Eastern New England Consumer-Owned Systems ("ENECOS") are: Braintree Electric Light Department, Georgetown Municipal Light Department, Groveland Electric Light Department, Littleton Electric Light & Water Department, Middleton Electric Light Department, Middleborough Gas & Electric Department, Norwood Light & Broadband Department, Pascoag (Rhode Island) Utility District, Rowley Municipal Lighting Plant, Taunton Municipal Lighting Plant, and Wallingford (Connecticut) Department of Public Utilities. Wellesley Municipal Light Plant, which intervened in this proceeding as one of the ENECOS, did not join in the ENECOS' request for rehearing.

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

[85] Under 16 USC § 825l(a), the FERC retains the right to address the rehearing request in a future order, modifying or setting aside its order, in whole or in part, up until the record of the proceeding is filed with a court of appeals. *See* n. 89 *infra*.

IV. OATT Amendments / TOAs / Coordination Agreements

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

On September 17, 2020, the FERC issued an order ("*CIP IROL Allegheny Order*")[86] addressing arguments raised by the IROL-Critical Facility Owners[87] in their request for rehearing of the FERC's *CIP IROL Cost Recovery Order*.[88] As it is permitted under section 313(a) of the FPA[89] (since the record of this proceeding has not yet been filed in an appeal before the DC Circuit), the FERC modified the discussion in the *CIP IROL Cost Recovery Order* but reached the same the result. Of note, the FERC continued "to interpret the language in section 2.2(A) of Schedule 17 as allowing recovery only for those costs incurred on or after the effective date of the relevant individual FPA section 205 filing"[90] (which provides the legally required notice of a potential rate adjustment). The FERC did note that "IROL-Critical Facility Owners may seek recovery of the undepreciated costs of any such past capital expenditures to comply with the IROL-CIP requirements. This may include a return of and on such previously-incurred costs, as well as any appropriate prospective costs, in their FPA section 205 filings submitted to the Commission pursuant to Schedule 17."[91] If you have any questions concerning this proceeding, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Order 845* Compliance Filing II (ER19-1951-002)**

On September 17, 2020, the FERC accepted the July 17, 2020 additional compliance filing jointly submitted by ISO-NE, NEPOOL and the PTO AC ("*Order 845* Compliance Filing II") in response to the March 19, 2020 order[92] conditionally accepting the first set of changes filed in response to the requirements of *Order 845* ("*Order 845* Compliance Filing I").[93] The changes in *Order 845* Compliance Filing II were accepted effective as of March 19, 2020, as requested. Unless the September 17 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, 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.[94] Among other things, those changes included: (i) updates and enhancements to the credit insurance provisions; (ii) updates to the

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[86] *ISO New England Inc.*, 172 FERC ¶ 61,251 (Sep. 17, 2020) ("*CIP IROL Allegheny Order*").

[87] "IROL-Critical Facility Owners" are Calpine, Cogentrix, Cross-Sound Cable, FirstLight, NextEra, NRG, and Vistra.

[88] *ISO New England Inc.*, 171 FERC ¶ 61,160 (May 26, 2020) ("*CIP IROL Cost Recovery Order*").

[89] 16 U.S.C. § 825l(a) (2020) ("Until the record in a proceeding shall have been filed in a court of appeals, as provided in subsection (b), the Commission may at any time, upon reasonable notice and in such manner as it shall deem proper, modify or set aside, in whole or in part, any finding or order made or issued by it under the provisions of this chapter.").

[90] *CIP IROL Allegheny Order* at P 11.

[91] *Id.* at P 22.

[92] *ISO New England Inc. and Participating Transmission Owners Admin. Comm.*, 170 FERC ¶ 61,209 (Mar. 19, 2020) ("*Order 845 Compliance Filing Order*"). The *Order 845 Compliance Filing Order* identified a number of ways in which *Order 845* Compliance Filing I only partially or did not comply at all with *Order 845.* The *Order 845 Compliance Filing Order* directed changes that needed to include additional justification for proposed changes or revisions that make no modification to the *pro forma* LGIA/LGIP in the following areas: Stand-Alone Network Upgrades definition, Interconnection Customer's ability to exercise the option to build; Option to Build Cost Recovery; Determination of Contingent Facilities; requesting interconnection service below generating facility capacity; Provisional Interconnection Service; definition of Surplus Interconnection Service; and Surplus Interconnection Service process.

[93] *ISO-NE New England Inc. and New England Power Pool Participants Comm.*, Docket No. ER19-1951-002 (Sep. 17, 2020).

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

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 August 31, Versant Power filed an amended version of Schedule 20A-VP in order to reflect the renaming of Emera Maine as Versant Power and to correct certain typographical errors. A November 1, 2020 effective date was requested. Comments on this filing were due on or before September 21, 2020; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 22: NSTAR/Vineyard Wind LGIA (ER20-2489)**

On September 17, the FERC accepted a non-conforming LGIA by and among ISO-NE, NSTAR and Vineyard Wind, LLC ("Vineyard Wind"), effective July 10, 2020, as requested.[95] As previously reported, the LGIA is non-conforming in that it contains certain deviations in Appendix C.3 necessary to reflect unique characteristics of the proposed interconnection -- the location of the met gathering station(s) and the layout of the facility due to its location in offshore federal waters rather than onshore. Unless the September 17 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-NEP: DWW E&P Agreement (ER20-2454)**

On September 14, the FERC accepted the Engineering & Procurement Agreement ("E&P Agreement") between NEP and DWW REV I, LLC ("DWW") filed by the New England Power Company ("NEP") under Schedule 21-NEP.[96] The E&P Agreement (designated as Service Agreement No. E&P-NEP-01) is to facilitate NEP's performance of preliminary engineering and certain procurement-related activities in connection with the interconnection of DWW's Revolution Wind project, a proposed 704 MW offshore wind generating facility project, to NEP's transmission system at the 115kV Davisville substation in Washington County, Rhode Island, prior to the parties entering into an LGIA. The E&P Agreement was accepted effective as of June 17, 2020, as requested. Unless the September 14 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

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[95] *ISO New England Inc. and NSTAR Elec. Co.*, Docket No. ER20-2489 (Sep. 17, 2020) (unpublished letter order). The LGIA was designated as Original Service Agreement No. LGIA-ISONE/NSTAR-20-01 under Schedule 22 of the ISO-NE OATT.

[96] *New England Power Co.*, Docket No. ER20-2454 (Sep. 14, 2020) (unpublished letter order).

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).

- **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,*[97] and certified by Settlement Judge Dring[98] to the Commission,[99] 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*[100] *and 531-B*[101] also remains pending. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

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

♦ Central Maine Power
♦ National Grid
♦ United Illuminating

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[97] *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.

[98] 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.

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

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

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

♦ Emera Maine	♦ NHT	♦ VTransco
♦ Eversource	♦ NSTAR	

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

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

On August 10, 2020, ISO-NE filed its Capital Projects Report and Unamortized Cost Schedule covering the second quarter 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 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 ($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). Comments on this filing were due on or before August 31. On August 25, NEPOOL filed comments supporting the filing. Eversource and National Grid filed doc-less interventions. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **Interconnection Study Metrics Processing Time Exceedance Report Q2 2020 (ER19-1951)**

On August 14, 2020, ISO-NE filed, as required,[102] public and confidential[103] versions of its Interconnection Study Metrics Processing Time Exceedance Report (the "Exceedance Report") for the Second Quarter of 2020 ("2020 Q2"). ISO-NE reported that all four ***Interconnection Feasibility Study ("IFS") reports*** delivered to Interconnection Customers were delivered later than the best efforts completion timeline.[104] The average mean time from ISO-NE's receipt of the executed IFS Agreement to delivery of the completed IFS report to the Interconnection Customer was 241 days. Three ***System Impact Study ("SIS") reports*** were delivered to Interconnection Customers, with one delivered later than the best efforts completion timeline of 270 days. The average mean time from ISO-NE's receipt of the executed SIS Agreement to delivery of the completed SIS report to the Interconnection Customer was 227 days. There were no Interconnection Requests with projects in the Interconnection Facilities Study phase of the interconnection process. Section 4 of the Report identifies steps ISO-NE has identified to remedy issues and prevent future delays, including implementing certain interconnection studies timeline modifications accepted in the *Order 845* compliance proceeding, moving to earlier in the process certain Interconnection Customer data reviews, and enhanced information sharing and coordination efforts with Interconnecting TOs. This report was not noticed for public comment.

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[102] Under section 3.5.4 of ISO-NE's Large Generator Interconnection Procedures ("LGIP"), ISO-NE must submit an informational report to the FERC describing each study that exceeds its Interconnection Study deadline, the basis for the delay, and any steps taken to remedy the issue and prevent such delays in the future. The Exceedance Report must be filed within 45 days of the end of the calendar quarter, and ISO-NE must continue to report the information until it reports four consecutive quarters where the delayed amounts do not exceed 25 percent of all the studies conducted for any study type in two consecutive quarters.

[103] ISO-NE requested that the information contained in Section 3 of the un-redacted version of the Exceedance Report, which contains detailed information regarding ongoing Interconnection Studies and if released could harm or prejudice the competitive position of the Interconnection Customer, be treated as confidential under FERC regulations.

[104] 90 days from the Interconnection Customer's execution of the study agreement.

- **FCA14 Fuel Security Reliability Review Info Filing (ER18-2364)**

Pursuant to the *Fuel Security Retention Proposal Order*, ISO-NE filed on September 25, 2020 its informational filing assessing the study triggers, assumptions and scenarios that it used in performing its fuel security reliability review for FCA14 in comparison to the actual conditions experienced during Winter 2019-2020. This filing is for informational purposes only and will not be noticed for public comment or subject to a FERC order.

- **ISO-NE FERC Form 3Q (2020/Q2) (not docketed)**

On August 26, 2020, ISO-NE submitted its 2020/Q2 FERC Form 3Q (Quarterly financial report of electric utilities, licensees, and natural gas companies). FERC Form 3-Q is a quarterly regulatory requirement which supplements the annual FERC Form 1 financial reporting requirement. These filings are not noticed for comment.

- **ISO-NE Third Revised 2018 FERC Form 714 (not docketed)**

On September 3, 2020, ISO-NE submitted a third revision[105] to its Annual Electric Balancing Authority Area and Planning Area Report (Form 714)[106] for calendar year 2018. The 2018 Form 714 was revised to include the addition of Real-Time DR to Net Generation for all months beginning in June (25,500 MWh total for the year). These values are now included in ISO-NE's NEL totals. These filings are not noticed for comment.

IX. Membership Filings

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

On August 28, 2020, NEPOOL requested that the FERC accept (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). Comments on this filing were due on or before September 18; none were filed. This matter is pending before the FERC.

- **August 2020 Membership Filing (ER20-2581)**

On September 22, 2020, the FERC accepted (i) the memberships of: Blueprint Power Technologies Inc. (Provisional Member); and Advanced Energy Economy Inc. (Fuels Industry Participant); and (ii) the termination of the Participant status of two End Users, New Hampshire Industries Inc. and The Energy Council of Rhode Island ("TEC-RI").[107] Unless the September 22 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,

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[105] The first revision, filed May 31, 2019, converted Column e in Part III Schedule 2 from GWh (as reported in the original filing) to MWh; The second revision, filed June 3, 2019, included complete Balancing Authority names in Part II Schedules 4 and 5 and,in Part III - Schedule 1, included the full utility names for each of the nodes.

[106] Through its Form 714 filings, ISO-NE reports, among other things, generation in the New England Control Area, actual and scheduled inter-balancing authority area power transfers, and net energy for load, summer-winter generation peaks and system lambda. The FERC uses the data to obtain a broad picture of interconnected balancing authority area operations including comprehensive information of balancing authority area generation, actual and scheduled inter-balancing authority area power transfers, and load; and to prepare status reports on the electric utility industry including review of inter-balancing authority area bulk power trade information. Planning area data is used to monitor forecasted demands by electric utility entities with fundamental demand responsibility, and to develop hourly demand characteristics.

[107] *New England Power Pool Participants Comm.*, Docket No. ER20-2581 (Sep. 22, 2020) (unpublished letter order).

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.

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,[108] 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[109] 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)**

Still pending before the FERC are the proposed changes, filed on February 21, 2020, 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"). The changes

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[108] 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").

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

remove references to Load Serving Entity (which is no longer an applicable entity), add Underfrequency Load Shedding ("UFLS")-Only Distribution Provider to PRC-006-3 as an applicable entity, and make consistent across the Standards the use of the term "Planning Coordinator". NERC asked that revised Reliability Standards become effective (and the currently effective versions be retired) on the first day of the first calendar quarter that is three months following FERC approval. Comments on the Revised Standards were due on or before March 23, 2020; none were filed. American Municipal Power ("AMP") submitted a doc-less intervention.

On July 17, 2020, the FERC issued a notice of revised information collections that would impact these Reliability Standards and requested that comments on the collections of information be filed in this proceeding on or before September 22, 2020;[110] none were filed.

- **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,[111] 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 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

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[110] *See Fed. Reg.* July 24, 2020 (Vol. 85, No. 143) pp. 44,875-44,880.

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

("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 or cloud computing services.[112] On March 25, 2020, Joint Associations[113] 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 ISO/RTO Council ("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,[114] 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."[115] 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.[116]

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*[117] (the "MOD A Reliability Standards"). The FERC intends to coordinate the effective dates for the retirement of the MOD A Reliability Standards with successor

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

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

[114] *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).

[115] *Order 873* at P 2.

[116] *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.

[117] *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.

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).[118]

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

On August 24, 2020, NERC submitted its proposed Business Plan and Budget, as well as the Business Plans and Budgets for the Regional Entities, including NPCC, for 2021. FERC regulations[119] require NERC to file its proposed annual budget for statutory and non-statutory activities 130 days before the beginning of its fiscal year (January 1), as well as the annual budget of each Regional Entity for their statutory and non-statutory activities, including complete business plans, organization charts, and explanations of the proposed collection of all dues, fees and charges and the proposed expenditure of funds collected. NERC reports that its proposed 2021Funding requirement represents an overall decrease of approximately 1.0% over NERC's 2020 Funding requirement. The NPCC U.S. allocation of NERC's net funding requirement is $4.44 million. NPCC has requested $16.4 million in statutory funding (a U.S. assessment per kWh (2020 NEL) of $0.0000494) and $1 million for non-statutory functions. Comments on this filing were due on or before September 14, 2020; none were filed. This matter is pending before the FERC.

- **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: 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 are due on or before October 9, 2020. Thus far, Public Citizen has filed a doc-less intervention.

- **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 construction of the Line.[120] 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.

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

On September 21, 2020, CL&P filed a Preliminary Agreement for Design, Engineering and Construction services (the "D&E Agreement") between itself and The University of Connecticut ("UConn"). The D&E Agreement sets forth the terms and conditions under which CL&P will undertake preliminary design and engineering activities

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

[119] 18 CFR § 39.4(b) (2014).

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

to increase the real power capacity of the transmission interconnection service to UConn's large generating facility. CL&P requested that the D&E Agreement be accepted for filing as of the date of filing, or September 21, 2020. Comments on this filing are due on or before October 9. 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 described in Section VI (ER20-2489) above. The D&E Agreement terminated by its terms as of the effective date of the LGIA. A July 10, 2020 effective date to coincide with the effective date of the LGIA was requested. Comments on this filing are due on or before October 9. 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.)**

On September 3 and 16, 2020, New England Power Company ("NEP") filed notices of cancellation of its LGIAs with GreatRiver Hydro (f/k/a TransCanada Hydro Northeast) governing the interconnection of the following hydroelectric facilities: (i) Moore (ER20-2897); (ii) Vernon (ER20-2896); and (iii) Comerford (ER20-2815). NEP, ISO-NE and Great River Hydro entered into a fully conforming, standard LGIAs superseding the LGIAs to be cancelled. NEP requested that the cancellation notice be 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). If you have any questions concerning these matters, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On August 24, NSTAR filed an Agreement between NSTAR and H.Q. Energy Services (U.S.), Inc. ("HQUS") for the continued reassignment (through May 31, 2021) of NSTAR's Use Rights on the Phase I/II HVDC Transmission Facilities ("Transfer Agreement") to HQUS. Comments on this filing were due on or before September 14, 2020; none were filed. Doc-less interventions were filed by HQ US and National Grid (out-of-time). 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).

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

On August 14, 2020, CMP filed executed second amendments to 7 of its previously filed and accepted, cost-based transmission service agreements ("TSAs") with the participants that will fund the construction, operation and maintenance of CMP's portion of a the NECEC Transmission Line.[121] 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. Comments on the second amendments were due on or before September 4, 2020; none were filed. Doc-less interventions were filed by Eversource, HQ US and National Grid. 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).

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

On July 27, 2020, VTransco filed a notice of cancellation of two agreements,[122] both entered into in 2006, among Vermont Electric Power Company, Inc. ("VELCO"), Central Vermont Public Service Corporation

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[121] The second amendments to the 7 TSAs were separately docketed as follows: Eversource (ER20-2674); National Grid (ER20-2675); Unitil (ER20-2676); HQUS/Eversource (ER20-2677); HQUS/National Grid (ER20-2678); HQUS/Unitil (ER20-2679); and HQUS Additional (ER20-2680).

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

("CVPS"), Green Mountain Power Corporation ("GMP"), and VTransco, which are no longer in use. VTransco requested that the notice of cancellation be accepted for filing as of July 30, 2020. Comments on this filing were due on or before August 17, 2020; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement Cancellation: CL&P-NTE CT (ER20-2327)**

On September 3, 2020, the FERC accepted CL&P's notice of cancellation of its Design, Engineering and Procurement Agreement (the "D&E Agreement") with NTE Connecticut, LLC ("NTE CT").[123] The D&E Agreement, which set forth the terms and conditions under which CL&P would undertake certain preliminary design and engineering activities on the Interconnection Facilities that were identified in ISO-NE's studies, prior to execution of a Standard Large Generator Interconnection Agreement ("LGIA"), expired when an LGIA was signed on June 16, 2020. The notice of cancellation was accepted for filing as of June 16, 2020, as requested. Unless the September 3 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)**

VELCO's filing, as an agent of the Joint Owners, that describes why no changes were required to the Phase II Vermont Dedicated Metallic Neutral Return Conductor ("DMNRC") Support Agreement[124] as a result of *Order 864*, remains pending before the FERC. Comments on this filing were due April 22 and were filed by GMP, which supported the filing and agreed with VELCO that no *Order 864* compliance filing is necessary. The IRH Management Committee, Eversource and National Grid intervened doc-lessly. 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*[125] and *Order 864-A,*[126] 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 al remain pending):

Date Filed	Docket	Transmission Provider	Date Accepted
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

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[123] *The Conn. Light and Power Co.*, Docket No. ER20-2327 (Sep. 3, 2020) (unpublished letter order).

[124] 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.

[125] *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*"). requiring all public utility transmission providers with transmission rates under an OATT, a transmission owner tariff, or a rate schedule to revise those rates to account for changes caused by the 2017 Tax Cuts and Jobs Act ("2017 Tax Law"). Specifically, for transmission formula rates, Order 864 requires public utilities (i) to deduct excess ADIT from or add deficient ADIT to their rate bases and adjust their income tax allowances by amortized excess or deficient ADIT; and (ii) to incorporate a new permanent worksheet into their transmission formula rates that will annually track ADIT information.

[126] *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*").

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

XII. Misc. - Administrative & Rulemaking Proceedings

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

On June 17, 2020, the FERC issued a notice that it would convene a Commissioner-led technical conference on September 30, 2020, from 9:00 am – 6:00 pm. The purpose of the conference, which will be held electronically, is 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 is a response to (i) the April 14, 2020 request by Interest Parties,[127] 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.

Since the last Report, the FERC issued a supplemental notice (September 16) with a revised agenda and list of panelists, with changes to the agenda since the August 28, 2020 notice identified in italics. Of note, panelists during the day will include Gordon van Welie and Matt White. There is no fee for attendance, and the conference will be webcast for the public to attend electronically. Information on this technical conference, including a link to the webcast, are posted on this conference's event page on the FERC's website (https://www.ferc.gov/news-events/events/technical-conference-regarding-carbon-pricing-organized-wholesale-electricity).

- **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. This matter is pending before the FERC.

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[127] "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.

- **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, 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.

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

On January 8, 2018, the FERC initiated a Grid Resilience in RTO/ISOs proceeding (AD18-7)[133] and terminated the DOE NOPR rulemaking proceeding (RM18-1).[134] In terminating the DOE NOPR proceeding, the

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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).

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

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

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

Industry Comments. Following a 30-day extension issued on March 20, 2018, reply comments were due on or before May 9, 2018. NEPOOL's comments, which were approved at the May 4 meeting, were filed May 7, and were among over 100 sets of initial comments filed. A summary of the comments that seemed most relevant to New England and NEPOOL was circulated to the Participants Committee on May 15 and is posted on the NEPOOL website. On May 23, NEPOOL submitted a limited response to four sets of comments, opposing the suggestions made in those pleadings to the extent that the suggestions would not permit full use of the Participant Processes. Supplemental comments and answers were also filed by FirstEnergy, MISO South Regulators, NEI, and EDF. Exelon and American Petroleum Institute filed reply comments. FirstEnergy included in this proceeding its motion for emergency action also filed in ER18-1509 (ISO-NE Waiver Filing: Mystic 8 & 9), which Eversource answered (in both proceedings). Reply comments were filed by APPA and AMP and the Nuclear Energy Institute ("NEI") moved to lodge presentations by the National Infrastructure Advisory Council. On December 6, the Harvard Electricity Law Initiative filed a comment suggesting that, as a matter of law, "Commission McNamee cannot be an impartial adjudicator in these proceedings" and "any proceeding about rates for 'fuel-secure' generators" and should recuse himself. Similarly, on December 18, "Clean Energy Advocates"[136] requested Commissioner McNamee recuse himself from these proceedings. These matters remain pending before the FERC.

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

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

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

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

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[137] proposing to revise its existing transmission incentives policy and corresponding regulations.[138] 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 <u>and</u> an additional 50 basis point adder for transmission projects that demonstrate *ex post* cost savings that fall in the 90th percentile of transmission projects studied over the same sample period, as measured at the end of construction.
- ♦ ***ROE for Reliability Benefits***. A 50 basis point adder for transmission projects that can demonstrate potential reliability benefits by providing quantitative analysis, where possible, as well as qualitative analysis.
- ♦ ***Abandoned Plant Incentive***. 100 percent of prudently incurred costs of transmission facilities selected in a regional transmission planning process that are cancelled or abandoned due to factors that are beyond the control of the applicant. Recovery from the date that the project is selected in the regional transmission planning process.
- ♦ ***Eliminate Transco Incentives***.
- ♦ ***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[139] 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).

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

[138] 18 CFR 35.35 (2020).

[139] 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 872*: Pricing and Eligibility Changes to PURPA Regulations (RM19-15)**

On July 16, 2020, the FERC issued its final rule[140] approving pricing and eligibility revisions to its long-standing regulations implementing sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA").[141] Those regulations address the obligation of electric utilities to purchase power produced by "qualifying facilities" or "QFs" at rates that must be "just and reasonable to the electric consumers of the electric utility and in the public interest, and not discriminate against" those QFs.[142] *Order 872* implements the following significant revisions:

- ***State Flexibility in Setting QF Rates***: Previous regulations required that rates paid to qualifying facilities (QFs) under PURPA must be at "avoided costs" of the purchasing utility, with the QF electing whether to accept avoided cost rates that vary over a contract period or a fixed rate for the duration of the contract. *Order 872* eliminates that requirement; instead, states will have the option of requiring energy rates (but not capacity rates) in QF power sales contracts to vary with changes in the purchasing utility's "as-available" avoided costs at the time energy is delivered. If a state exercises this option, then a QF cannot elect to fix the energy rate but can continue to receive a fixed capacity rate for the term of its agreement with the purchasing utility. In addition, *Order 872* allows states in an ISO/RTO market to set the rate for as-available energy at a variable rate equal to the ISO/RTO LMP, based on a rebuttable presumption (rather than a *per se* rule as FERC proposed in its NOPR) that the LMP represents the as-available avoided costs of utilities located in that market. These regulations provide greater flexibility to the states in determining whether such rates accurately reflect the purchasing utility's avoided cost at the time of delivery. *Order 872* also permits states to set energy and capacity rates pursuant to competitive solicitation processes but only so long as those processes are transparent and nondiscriminatory. FERC, however, declined to adopt a NOPR proposal to permit states with retail competition to relieve their utilities from PURPA's mandatory purchase obligation.
- ***Decreases (to 5 MW) the Threshold for Rebuttable Presumption of Access to Nondiscriminatory, Competitive Markets***. PURPA regulations previously provided a rebuttable presumption that certain 20 MW or larger QFs located in ISO/RTO markets had nondiscriminatory access to those markets and exempted utilities from any purchase obligations from such resources. *Order 872* reduces the threshold from 20 MW to 5 MW (rather than 1 MW as proposed in the NOPR). QFs above 5 MW can challenge the presumption that they have nondiscriminatory access to wholesale markets based on a list of factors specified in *Order 872*, including barriers to connecting to the transmission grid and lack of affiliation with entities participating in RTO/ISO markets. This modification does not apply to QFs that are cogenerators, which are still subject to the 20 MW threshold.
- ***Updates the "One-Mile Rule"***. Under current PURPA regulations, a small power production facility must be 80 MW or less to be eligible for QF treatment. To prevent gaming of that rule (QF certification of multiple projects that, if combined, would otherwise exceed the 80 MW cap), *Order 872* establishes two irrebuttable presumptions: (1) facilities under common ownership located less than one mile apart that use the same energy resource will be aggregated into a single project for purposes of QF eligibility; and (2) facilities under common ownership located more than 10 miles apart that use the same energy resource will be presumed to be separate projects for QF eligibility. *Order 872* also establishes a rebuttable presumption that facilities under common ownership located more than one mile apart but less than 10 miles apart are located on a separate site and are not aggregated in determining whether they fall below the 80 MW cap. The FERC explained that this rule also will be applied to QFs developed by unaffiliated developers and later acquired by a single entity.

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[140] *Qualifying Facility Rates and Requirements; Implementation Issues Under the Public Utility Regulatory Policies Act of 1978*, Order No. 872, 172 FERC ¶ 61,041 (July 16, 2020) ("*Order 872*").

[141] 16 U.S.C. § 2601 et seq. (2018). PURPA was enacted to help lessen the dependence on fossil fuels and promote the development of power generation from non-utility power producers.

[142] 16 U.S.C. § 824a–3; PURPA, Sec. 210(a)-(b).

- ***Clarifies When a QF Establishes Its Entitlement to a Purchase Obligation***. *Order 872* requires a utility to purchase the power only from QFs that can demonstrate commercial viability and a financial commitment pursuant to objective and reasonable state-defined criteria. The FERC clarified that, to the extent that a permitting factor is relied upon, a QF need only show that it has applied for all required permits and paid all applicable fees, but not that it has obtained such permits or has a reasonable likelihood of obtaining such permits.
- ***Provides for Certification Challenges***. *Order 872* provides that interested stakeholders may challenge a QF self-certification or self-recertification. Challenges to recertifications, however, will be limited to those QFs making substantive changes (e.g., a change in electrical generating equipment that increases power production capacity by the greater of 1 MW or 5 percent of the previously certified capacity, or a change in ownership in which an owner increases its equity interest by at least 10 percent from the equity interest previously reported).

Order 872 will become effective December 31, 2020.[143] Requests for rehearing and/or clarification of *Order 872* were filed by California Utilities, EPSA, Northwest Coalition, One Energy Enterprises, Public Interest Organizations, SEIA, and Thomas Mattson. On September 17, 2020, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[144] The Notice confirmed that the 60-day period during which a petition for review of *Order 872* can be filed with an appropriate federal court was triggered when the FERC did not act on the requests for rehearing of *Order 872*. The Notice also indicated that the FERC would address, as is its right, the rehearing requests in a future order, and may modify or set aside its orders, in whole or in part, "in such manner as it shall deem proper." That order must be issued by the date that the record of the proceeding must be filed with the court of appeals.[145] Thus far, SEIA has petitioned the 9th Circuit Court of Appeals for review of *Order 872* (*see* Section XV below).

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

On September 17, the FERC issued a final rule ("*Order 2222*")[146] adopting reforms to remove what it found were barriers to the participation of distributed energy resource ("DER")[147] 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;

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[143] *Order 872* was published *Fed. Reg.* on Sep. 2, 2020 (Vol. 85, No. 171) pp. 54,638-54,740.

[144] *Qualifying Facility Rates and Requirements; Implementation Issues Under the Public Utility Regulatory Policies Act of 1978*, 172 FERC ¶ 62,154 (Sep. 11, 2020).

[145] *See* 16 USC § 825l(a) ("Until the record in a proceeding shall have been filed in a court of appeals, … the [FERC] may at any time, upon reasonable notice and in such manner as it shall deem proper, modify or set aside, in whole or in part, any finding or order made or issued by it under the provisions of this chapter.").

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

[147] 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."

(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* within [270 days of the publication date of *Order 2222* in the *Federal Register*].[148] 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.

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

As previously reported, *Order 860,*[149] issued three years after the FERC's *Data Collection NOPR,*[150] (i) revises the FERC's MBR regulations by establishing a relational database of ownership and affiliate information for MBR Sellers (which, among other uses, will be used to create asset appendices and indicative screens), (ii) reduces the scope of information that must be provided in MBR filings, modifies the information required in, and format of, a MBR Seller's asset appendix, (iii) changes the process and timing of the requirements to advise the FERC of changes in status and affiliate information, and (iv) eliminates the requirement adopted in *Order 816* that MBR Sellers submit corporate organization charts. In addition, the FERC stated that it will <u>not</u> adopt the *Data Collection NOPR* proposal to collect Connected Entity data from MBR Sellers and entities trading virtuals or holding FTRs. The FERC will post on its website high-level instructions that describe the mechanics of the relational database submission process and how to prepare filings that incorporate information that is submitted to the relational database. 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

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[148] As of the date of this Report, *Order 2222* has not been published in the *Federal Register*.

[149] *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).

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

an EIA code so that every ultimate upstream affiliate or other reportable entity has a FERC-assigned company identifiers ("CID"), Legal Entity Identifier,[151] 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,[152] 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.

- **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").[153] 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."[154] Comments on the *NAESB WEQ v. 003.3 Standards NOPR* are due on or before November 3, 2020.[155]

- ***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*,[156] 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.[157] The Version 003.2 Standards included NAESB's Version 003.1 revisions, which were the subject

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[151] 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.

[152] *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*").

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

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

[155] 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.

[156] *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*.

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

of an earlier NOPR.[158] 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.[159] 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.[160] The *Proposed Policy Statement* sets forth the approach the FERC would take going forward to ensure compliance with the filed rate doctrine and the rule against retroactive making. The proposed policy will both clarify and modify waiver standards, and in some instances, make it harder to obtain waivers.

Specifically, the FERC proposed the following guidance on filing procedures to implement its new approach for granting waivers of tariff provisions and to no longer grant retroactive waivers except as consistent with the *Proposed Policy Statement*:

1. *Style Requests as Requests for Remedial Relief*. Filings seeking relief in connection with actions or omissions that have already occurred prior to the date relief is sought from the FERC would be characterized as a request for remedial relief (rather than as a request for a waiver). In response to such a request, the FERC will focus on what remedy, if any, is required to cure acknowledged or alleged deviations from a filed tariff. “Waiver” is to be limited to (a) requests for prospective relief when a requested future deviation from the filed tariff has not yet occurred at the time a request is filed; or (b) petitions for remedial relief when a tariff expressly authorizes regulated entities to seek a remedial waiver from the FERC for past non-compliance with the filed tariff.

2. *Form of Filing*. When the entity requesting remedial relief is the entity that acted (or believes it may have acted) in a manner inconsistent with the tariff, such requests should be filed as petitions for declaratory order under Rule 207 of the FERC’s Rules of Practice and Procedure. When the filing entity alleges a different entity has acted in a manner inconsistent with the tariff, such requests should be filed as complaints under Rule 206. Given the filing fees associated with petitions for declaratory order, the industry was encouraged to directly address this aspect of the proposal.

3. *Expressly Request FERC Action pursuant to FPA section 309 or NGA section 16.4*. These provisions have been found to afford the FERC the latitude to remedy past non-compliance “provided the agency’s action conforms with the purposes and policies of Congress and does not contravene any terms of the Act.”

The FERC acknowledged that this Policy would represent a change from its past approach, particularly in situations where inadvertent failures to comply with ministerial tariff requirements have not been

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

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

[160] *Waiver of Tariff Requirements*, 171 FERC ¶ 61,156 (May 21, 2020) (“*Proposed Policy Statement*”).

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[161] 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).

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,[162] 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,[163] 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,[164] 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*.[165] 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").[166] In addition, the FERC clarified its policies governing the formation of proxy

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[161] 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.

[162] *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.

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

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

[165] *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*").

[166] 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.[166] The FERC also sought comment on whether any changes to its policies concerning public utility ROEs should

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.[167] 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[168] answered the New England TO's May 10 supplemental comments. On June 15, 2020, Joint Parties[169] 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.[170] WIRES submitted supplemental comments on June 18, 2020 requesting that the FERC take further action in this proceeding to "resolve the uncertainty surrounding its base ROE methodology and establish a policy consistent with the recommendations made in these comments" (recommending a framework that employs all four of the previously proposed ROE models, including the Expected Earnings model, along with certain modifications, to ensure that ROEs attract capital investment in needed transmission infrastructure). On June 24, EEI and WIRES requested the FERC issue a NOI regarding the FERC's policy for determining base ROE applicable to the electric industry as a whole. Six Cities answered Joint Parties on June 30. APPA answered EEI and WIRES' June 24 motion.

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

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[171] 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,[172] 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.

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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).

[167] 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.

[168] 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.

[169] "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.

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

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

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

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*[173] 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.[174] 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."[175] Accordingly, the FERC assessed a ***$20.16 million civil penalty*** and required BP to ***disgorge $207,169*** in "unjust profits it received as a result of its manipulation of the Houston Ship Channel Gas Daily index." The $20.16 million civil penalty was at the top of the FERC's Penalty Guidelines range, reflecting increases for having had a prior adjudication within 5 years of the violation, and for BP's violation of a FERC order within 5 years of the scheme. BP's penalty was mitigated because it cooperated during the investigation, but BP received no deduction for its compliance program, or for self-reporting. The *BP Penalties Order* also denied BP's request for rehearing of the order establishing a hearing in this proceeding.[176] 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.[177]

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

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

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

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

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

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

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[178] 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.[179]

The FERC also directed TGPNA to show cause why it should not be required to disgorge unjust profits of ***$9.18 million***, plus interest; TGPNA, Tran and Hall to show cause why they should not be assessed civil penalties (TGPNA - ***$213.6 million***; Hall - ***$1 million*** (jointly and severally with TGPNA); and Tran - ***$2 million*** (jointly and severally with TGPNA)). In addition, the FERC directed TGPNA's parent company, Total, S.A. ("Total"), and TGPNA's affiliate, Total Gas & Power, Ltd. ("TGPL"), to show cause why they should not be held liable for TGPNA's, Hall's, and Tran's conduct, and be held jointly and severally liable for their disgorgement and civil penalties based on Total's and TGPL's significant control and authority over TGPNA's daily operations. Respondents filed their answer on July 12, 2016. OE Staff replied to Respondents' answer on September 23, 2016. Respondents answered OE's September 23 answer on January 17, 2017, and OE Staff responded to that answer on January 27, 2017. This matter remains pending before the FERC.

- **New England Pipeline Proceedings**
  The following New England pipeline projects are currently under construction or before the FERC:
  - ***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 and Iroquois responded to a September 14 data request regarding Administrative and General (A&G) Expenses. In addition, Iroqious further supplemented its application with additional information on September 3, 18 and 21.

- **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

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

[179] 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.

and request for stay. On April 2, 2019, the FERC denied the NY DEC and Sierra Club requests for rehearing.[180] 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*.[181] 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,[182] and proceeded to find that the NY DEC was obligated to act on the application within one year, failed to do so, and so waived its authority under section 401 of the CWA.
- The FERC authorized the Companies to construct and operate pipeline, compression, and ancillary facilities in McKean County, Pennsylvania, and Allegany, Cattaraugus, Erie, and Niagara Counties, New York ("Northern Access Project") in an order issued February 3, 2017.[183] 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.[184] On February 2, 2019, the 2nd Circuit vacated the decision of the NY DEC and remanded the case with instructions for the NY DEC to more clearly articulate its basis for the denial and how that basis is connected to information in the existing administrative record. The matter is again before the NY DEC.
- On November 26, 2018, the Applicants filed a request at FERC for a 3-year extension of time, until February 3, 2022, to complete construction and to place the certificated facilities into service. The Applicants cited the fact that they "do not anticipate commencement of Project construction until early 2021 due to New York's continued legal actions and to time lines required for procurement of necessary pipe and compressor facility materials." The extension request was granted on January 31, 2019.

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

[181] *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).

[182] 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).

[183] *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*").

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

- On August 8, 2019, the NY DEC again denied Applicants request for a Water Quality Certification, and as directed by the Second Circuit,[185] 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.[186]

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 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). [*due to technological glitches in Westlaw, not all of the proceedings were able to be fully updated for this Report.*]

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[185] 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).

[186] *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).

- **Mystic 8/9 Cost of Service Agreement (20-1343; 20-1361, 20-1362; 20-1365, 20-1368)(consolidated); Underlying FERC Proceeding: ER18-1639**[187]
  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.[188] The cases have been consolidated into Case No. 20-1343. Appearances due October 8, 2020. Parties must file docketing statements and statement of issues to be raised by October 16 (October 19 for Parties in Case No. 20-1365). Dispositive motions and a Certified Index to the Record must be filed by October 23, 2020.

- ***CASPR*** **(20-1333)**
  Underlying FERC Proceeding: ER18-619[189]
  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). Appearances, together with a docketing statement, procedural motions (if any), statement of issues to be raised, and a statement of intent to utilize deferred joint appendix are due Entry of Appearance Form October 2, 2020. The Certified Index to the Record and dispositive motions, if any, are due October 19, 2020.

- ***Opinion 531-A*** **Compliance Filing Undo (20-1329)**
  Underlying FERC Proceeding: ER15-414[190]
  Petitioners: TOs' (CMP et al.)

On August 28, 2020, the TOs[191] 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*[192] decision. Among other submissions, the TOs must file by September 30, 2020 a docketing statement, statement of issues, and any procedural motions. Dispositive motions and a Certified Index to the Record must be filed by October 15, 2020. Appearances by others in this case must be filed by September 30, 2020.

- **2013/14 Winter Reliability Program Order on Compliance and Remand (20-1289, 20-1366) (consol.)**
  Underlying FERC Proceeding: ER13-2266[193]
  Petitioner: TransCanada

On July 30, 2020, TransCanada Power Marketing ("Petitioner") 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*.[194] Among other submissions, TransCanada must file by August 31, 2020 a docketing statement, statement of issues, and any procedural

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

[188] 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.

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

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

[191] 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.

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

[193] 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*").)

[194] 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.

motions. Dispositive motions and a Certified Index to the Record must be filed by September 14. Appearances by others in this case were due by August 31, 2020.

- **ISO-NE's Inventoried Energy Program (Chapter 2B) Proposal (19-1224***; 19-1247; 19-1252; 19-1253)(consolidated); Underlying FERC Proceeding: ER19-1428**[195]
  Petitioners: ENECOS (Belmont et al.) (19-1224); MA AG (19-1247); NH PUC/NH OCA (19-1252); Sierra Club/UCS (19-1253)

At the unopposed request of the FERC, the Court issued an order suspending the briefing schedule and remanded the record back to the FERC. In the request to suspend the briefing schedule and remand the record, the FERC stated that it "now has a quorum of Commissioners who can participate in the review of the ISO New England tariff filing," that remand "could obviate the need for a subsequent appeal by Petitioners", and it "anticipates issuing an order on remand within 90 days of this Court's order remanding the agency record and an order addressing the merits of any subsequent requests for rehearing within 180 days of the close of the 30-day period for applying for rehearing". (As reported in Section III above, the FERC issued the *IEP Remand Order* on June 18, 2020.) The Court directed the FERC to file status reports at 90-day intervals, the first of which was filed on July 17, 2020. Parties were directed to file motions to govern further proceedings in these consolidated cases within 30 days of the completion of the remand proceedings (now, September 16, 2020).

Other Federal Court Activity of Interest

- ***Order 872* (20-72728) (9th Cir.)**
  Underlying FERC Proceeding: RM19-15[196]
  Petitioner: SEIA
  On September 17, 2020, SEIA petitioned the 9th Circuit Court of Appeals for review of *Order 872*.

- **Allegheny Defense Project v. FERC (17-1098)**
  Underlying FERC Proceeding: CP15-138[197]
  Petitioner: Allegheny Defense Project

On June 30, in a decision[198] 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[199] 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,[200] there is

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[195] 162 FERC ¶ 61,127 (Feb. 15, 2018) ("*Order 841*"); 167 FERC ¶ 61,154 (May 16, 2019) ("*Order 841-A*").

[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] *Transcontinental Gas Pipe Line Co., LLC*, 159 FERC ¶ 62,181 (Feb. 3, 2017); *Transcontinental Gas Pipe Line Co., LLC*, 161 FERC ¶ 61,250 (Dec. 6, 2017).

[198] *Allegheny Def. Project v. FERC*, 964 F.3d 1, 2020 WL 3525547 (D.C. Cir. June 30, 2020).

[199] 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.

[200] 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

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.

- **FERC orders on PG&E Bankruptcy (19-71615) (9th Cir.)**
  Underlying FERC Proceeding: EL19-35, EL19-36[201]
  Petitioner: PG&E

On June 26, PG&E appealed the FERC's orders finding that it has concurrent jurisdiction with the bankruptcy courts to review and address the disposition of wholesale power contracts sought to be rejected through its bankruptcy. On July 11, PG&E moved to suspend the briefing schedule pending the Court's decision on whether to authorize direct appeal of a decision by the Bankruptcy Court in the Northern District of California. In a declaratory judgment, the Bankruptcy Court came to a completely different conclusion than the FERC and held that it has "original and exclusive jurisdiction over . . . [PG&E's] rights to assume or reject executory contracts under 11 U.S.C. § 365" and that the FERC "does not have concurrent jurisdiction, or any jurisdiction, over the determination of whether any rejections of power purchase contracts by [PG&E] should be authorized."[202] 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. This matter is now pending before the 9th Circuit.

- **PennEast Project (18-1128)**
  Underlying FERC Proceeding: CP15-558[203]
  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")[204] 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

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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.

[201] *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).

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

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

[204] 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.

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. Since the last Report, on June 29, 2020, a Joint Status Report was filed, noting developments since the May 4, 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."

- **Opinion 569/569-A: FERC's Base ROE Methodology (16-1325, 20-1227, 20-1240)**
  Underlying FERC Proceeding: EL14-12; EL15-45[205]
  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.

Since the last Report, 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.

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[205] *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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NEW ENGLAND POWER POOL

NEPOOL PARTICIPANTS COMMITTEE
OCT 1, 2020 MEETING, AGENDA ITEM #13

TO: NEPOOL Participants Committee Members and Alternates

CC: NESCOE, NECPUC, and ISO-NE

FROM: Nancy Chafetz, Chair of NEPOOL Participants Committee

DATE: September 23, 2020

RE: Process Update: Potential Pathways to New England's Future Grid

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I am writing to update you on proposed next steps for exploring potential alternative future pathways for New England in light of state energy and environmental laws. As I have previously explained, this "Pathways" process is intended to provide regional stakeholders the opportunity and forum to identify, explore and evaluate together potential alternative pathways/market frameworks that could be pursued to help transition New England to its future grid. This memorandum provides additional information on the current plans for these discussions between now and the end of the year.

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Pathways Presented & Discussed to Date

Pursuant to the proposed process worked out earlier this year among ISO and NESCOE representatives and your elected Chair and Sector Vice-Chairs, at the Participants Committee Summer Meeting, a panel of speakers shared their insights and experiences on the various opportunities and challenges associated with efforts to decarbonize electric grid systems across the country. NEPOOL has continued those discussions at every Participants Committee meeting since then. At this point, the region has received presentations on the following four potential future pathways/market frameworks (listed here in the order that they were presented and discussed): (1) Forward Clean Energy Market (FCEM); (2) Carbon Pricing; (3) Energy-Only Market; and (4) Alternative Reliability Assurance Frameworks. All presentation materials on these potential options/pathways can be accessed at NEPOOL's dedicated webpage on this subject (http://nepool.com/Fut_Grid_Poten_Pathways.php).

Additional Potential Pathways/Market Frameworks?

If anyone wishes to explore additional potential pathways through this NEPOOL process, please let me or NEPOOL Counsel know as soon as possible and no later than Friday, October 16. At the October 1 Participants Committee meeting, per the request of some NEPOOL members, we will hear about a fifth potential pathway/market framework, which is being referred to as the "Integrated Clean Capacity Market". Kathleen Spees of The Brattle Group has been exploring the potential mechanics of this alternative pathway with various members and will describe it for regional stakeholders at next week's meeting. Time will also be set aside at the November 5 Participants Committee meeting in case any other potential pathways/market constructs are identified between now and October 16.

Next Steps: Discussion & Assessment of Tradeoffs

As promised, at the October 1 Participants Committee meeting, we will also begin to explore various questions, implications and tradeoffs associated with each identified pathway (i.e., the pros and cons of each pathway). As I reported at the September Participants Committee meeting, NEPOOL has retained Dr. Frank Felder to assist with that exploration. (Recall that Frank Felder presented at our Summer Meeting on the advantages and disadvantages of various markets around the globe). To be clear, Dr. Felder is **not** being asked to recommend a particular proposal/pathway. He is being asked only to provide his independent observations on the potential impact of those various pathways (1) in helping to advance the State's clean energy policy objectives and (2) on market efficiency. Dr. Felder will begin that discussion at next week's meeting, with a focus on the first two potential market frameworks that were discussed in August (the FCEM and carbon pricing concepts).

In November, we will hear about any other pathways proposed for consideration and Dr. Felder will present his preliminary observations on the remaining pathways described in September and October. Through the remainder of the year, the plan is for Dr. Felder to update his observations and analysis based on further information and stakeholder feedback, to add observations about any new pathways that may be presented in November, and to finalize a written report reflecting his efforts.[1] Hopefully this process will facilitate constructive exchanges among stakeholders on the relative merits of each identified pathway.

To help advance our upcoming discussions and inform Dr. Felder's assessment, we welcome and look forward to your thoughtful feedback, questions and comments during the NPC meetings. We also encourage you to provide any written materials on the identified pathways for consideration by Dr. Felder as well as to inform all those participating in this process. Any such submitted materials will be made publicly available on NEPOOL's website.

Thank you for your engagement to date. I look forward to continuing the open and constructive dialogue as we explore potential future pathways for New England.

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[1] Dr. Felder's work product will reflect his independent views and opinions and not necessarily the institutional views of NEPOOL, state officials participating in the discussion, ISO-NE, or any individual NEPOOL Participant or groups of Participants.

The Integrated Clean Capacity Market

A Design Option for New England's Grid Transition

October 1, 2020

PRESENTED TO

New England Power Pool

PRESENTED BY

Kathleen Spees

Brattle

What is an “Integrated Clean Capacity Market”?

Design Concept: Three-year forward market that attracts the optimal resource mix for reliability and state policy goals. Market would maintain key elements from today’s market, but would be a fit-for-purpose market for achieving the 80-100% clean electricity future

How does the Integrated Clean Capacity Market compare to other options in consideration?

Any useful path forward for New England will have to include a package of at least one solution meeting both of the central design objectives:

Solutions for Achieving Resource Adequacy Objectives	Solutions for Achieving State Policy Objectives
Energy-only market	Carbon pricing
Integrated planning & contracting	Integrated planning & contracting
Forward capacity market	Forward clean energy market

Integrated Clean Capacity Market

is a natural "package" for achieving a clean, reliable resource mix

What is an “Integrated Clean Capacity Market”?

The **Integrated Clean Capacity Market** would be a centralized, three-year forward market for procuring capacity and clean energy needs

Demand

- **Capacity:** ISO-NE establishes the quantity of capacity need (mandatory)
- **Clean Energy:** States & customers establish demand for unbundled clean energy attribute credits (CEACs)

Co-Optimized Auction Clearing

- Broad regional market
- Three-year forward auction
- Co-optimized procurement of unbundled capacity and CEACs
- 7-12 year price lock-in for new

Supply

- All resources can compete
- Fossil resources can sell only capacity
- Clean resources can sell both capacity and CEACs

Key design elements

Design Element	Resource Adequacy Objectives	Clean Electricity Objectives
Responsible Entity for Defining the Need	• **ISO New England**	• **State policymakers** • **Voluntary buyers** (retailers, companies)
Product Definition	• Unforced capacity (UCAP MW) • Keep locational specificity (as today) • *Consider also specifying*: separate summer and winter products & “flexible” capacity needs	• Clean energy attribute credit (CEAC) • States would make an effort to align definitions into a uniform product to the extent possible (though multiple products would be accommodated as needed) • *Consider*: “dynamic” CEAC product
Supply Eligibility	• All clean and fossil resources are eligible • ELCC-based accounting for resource-neutral capacity values (by location, season, and flexibility)	• All clean resources are eligible for a “base” product • All revenues are considered “in market” • States can specify technology (but aim to limit the number and size to maximize competition)
Quantity to Procure	• Quantity needed to support 1-in-10 • Based on advanced reliability modeling that considers resource characteristics & flexibility needs in the clean grid	• States and customers decide the quantity needed • Pre-existing contracts are fully accounted for in this market as self-supply
Willingness to Pay	• Sloping demand curves for each capacity product • Hierarchy of needs reflected in price formation (e.g. import-constrained and “flexible” capacity prices are equal or greater than system/traditional capacity prices)	• States submit sloping demand curves for state-mandated CEAC demand • Voluntary buyers can submit price-quantity pairs to exceed state mandates

How might the capacity market need to evolve to align with the 80-100% clean electricity future?

What FCM elements will…

Continue to work well?

- Broad regional market
- Unbundled products
- Technology-neutral competition
- Co-optimized, value-maximizing auction clearing
- Transmission constraints reflected
- Marginal-cost-based pricing
- Private sector takes most investment risk

Likely need evolution?

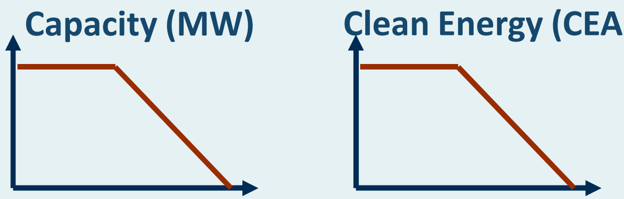
- Incorporate a new design objective: policy goals
- Define separate summer and winter capacity products (separate demand and supply accounting)?
- Define “flexible” capacity requirements?
- Adopt more accurate supply accounting for all resources based on effective load carrying capability (ELCC) and accounting for plant outage rates
- Advanced reliability modeling for the clean grid
- Eliminate out-of-market interventions
- Fully enable all emerging technologies

Example: Integrated Clean Capacity Market Auction Clearing

Co-optimized procurement of capacity and clean energy

BIDS

Demand



Supply

- Total annual resource cost ($)
- Capacity quantity (UCAP MW)
- Clean attribute quantity (CEAC)

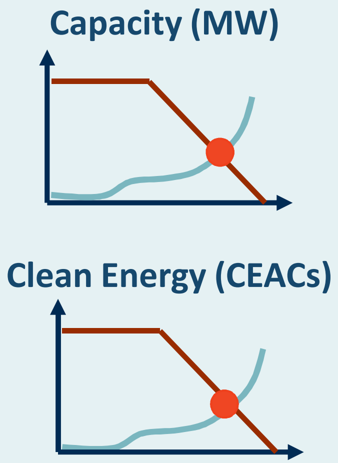
CO-OPTIMIZED AUCTION CLEARING

Similar to the FCM Clearing

- **Objective function:** Maximize social surplus (area under demand curves minus cleared resource cost)
- **Cleared resources:** Least cost resources for meeting capacity & CEAC demand
- **Price setting:** Marginal cost of meeting incremental demand

CLEARING RESULTS

Clearing Prices

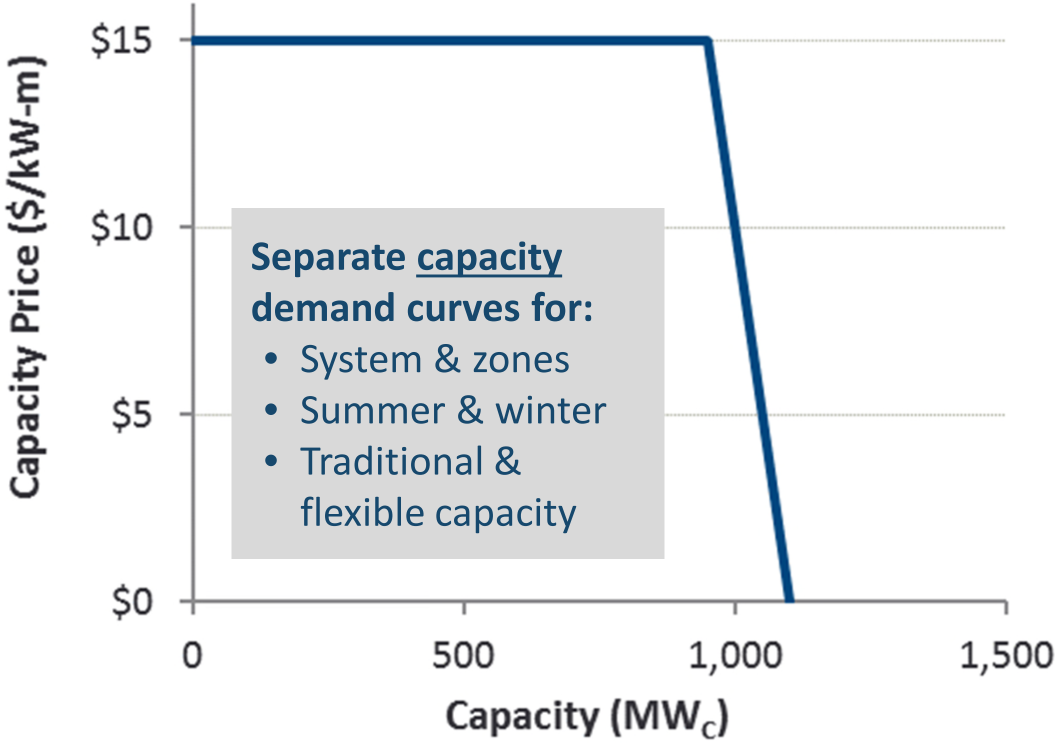


Cleared Resources

How is demand for capacity and clean energy expressed?

Separate demand curves would be used for each product

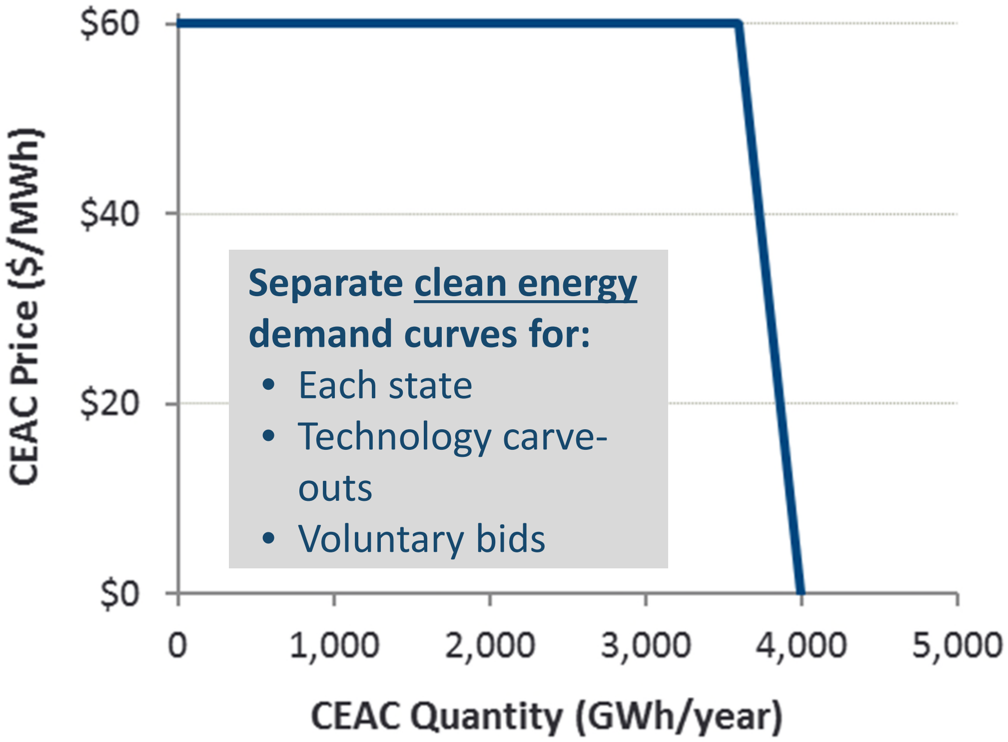
Capacity Demand Curve



Separate capacity demand curves for:

- System & zones
- Summer & winter
- Traditional & flexible capacity

Clean Energy Demand Curve



Separate clean energy demand curves for:

- Each state
- Technology carve-outs
- Voluntary bids

Note: Simplified example. Not intended to reflect New England.

How would resources offer?

Offer structure is <u>one price for two products</u>

- Offer price is total annual going-forward revenue requirement
- Unbundled CEAC and UCAP products clear at different prices
- Seller is presumed indifferent whether revenues are earned from selling capacity or CEAC

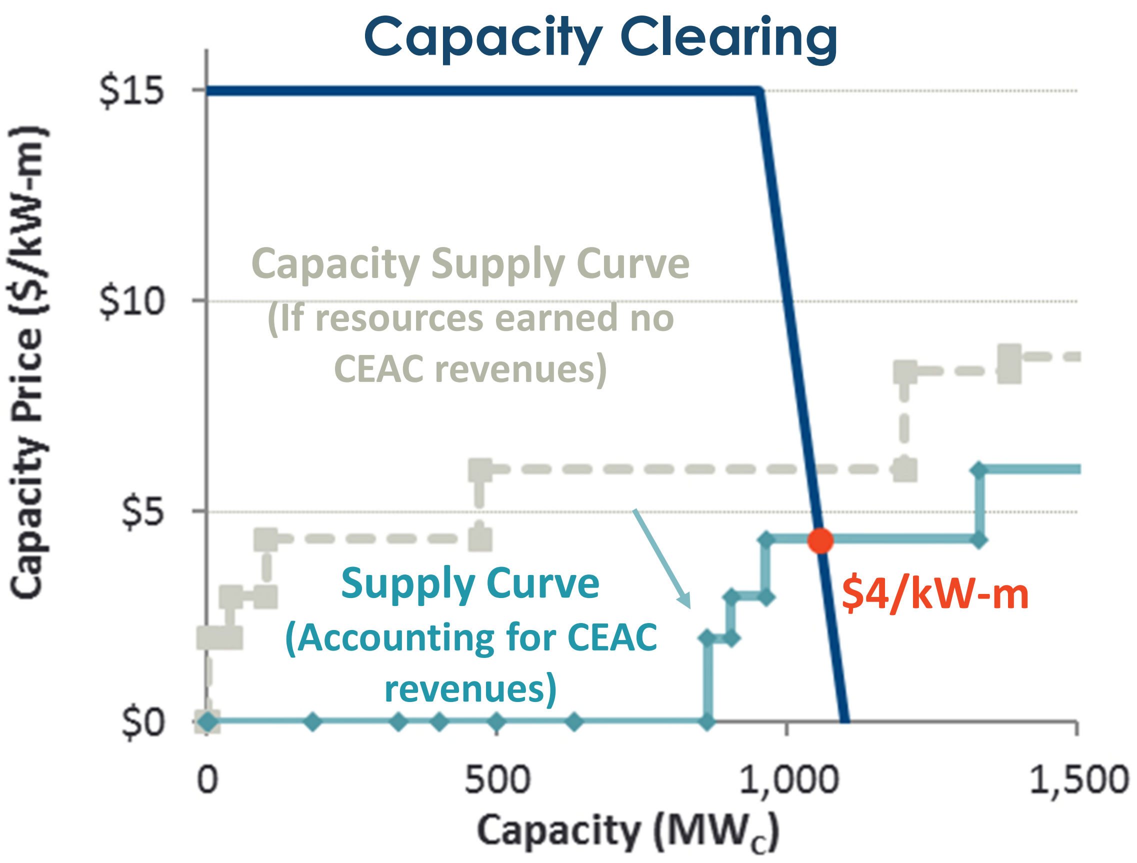
Example: Resource Offers

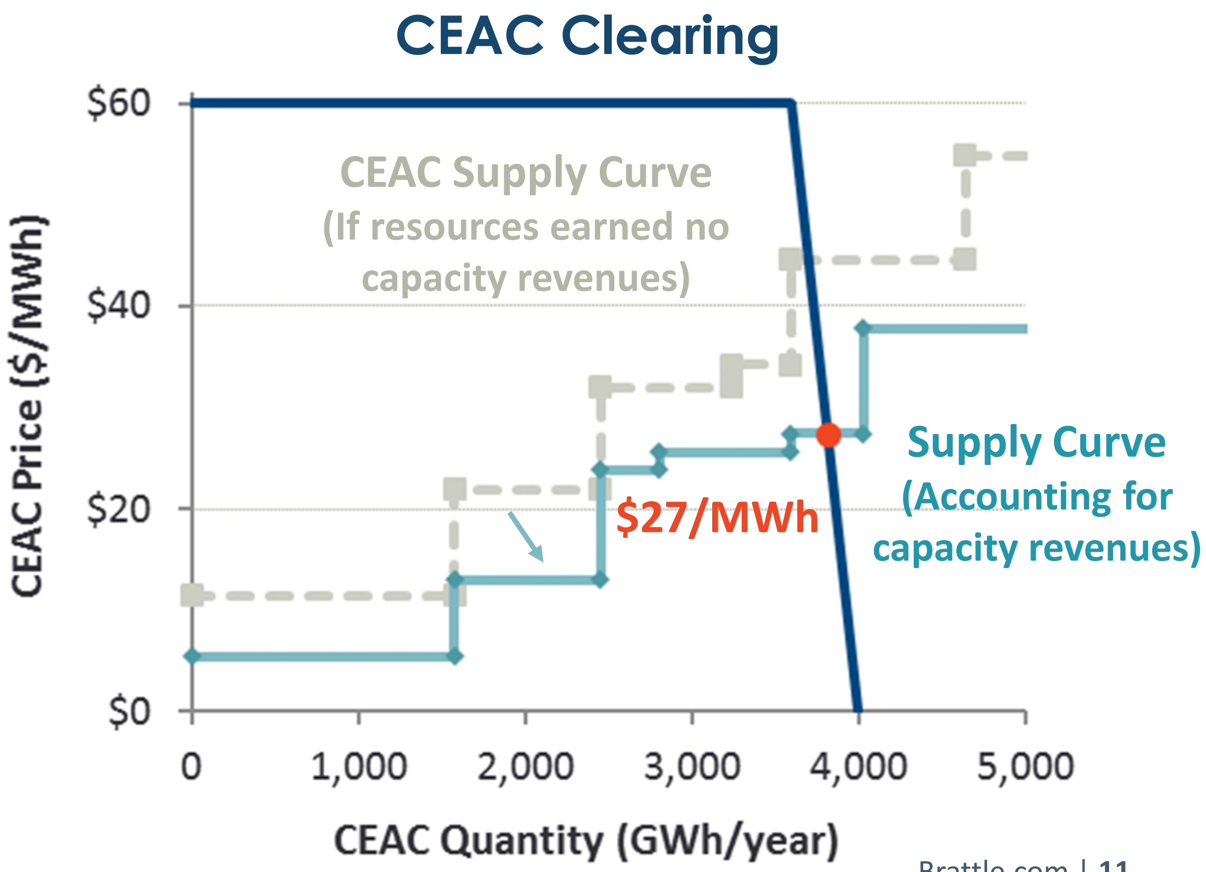
Type	Size *(ICAP MW)*	Qualified Capacity Rating *(UCAP MW)*	Qualified Clean Energy *(CEAC GWh)*	All-in Cost (less E&AS Revenues) *($/ICAP kW-y)*
Existing Gas	400	368	0	$48
New Gas	800	733	0	$66
Nuclear	200	180	1,577	$90
Solar	200	70	350	$60
Hydro	200	150	876	$96
Onshore Wind	300	96	788	$84
Offshore Winc	300	135	1,051	$156
Storage	250	230	438	$96
DR	60	60	0	$36
EE	40	40	0	$24
Total	**2,750**	**2,062**	**5,081**	

Note: Simplified example. Not intended to reflect New England.

How are prices set?

Co-optimized price formation reflects marginal cost of each product.

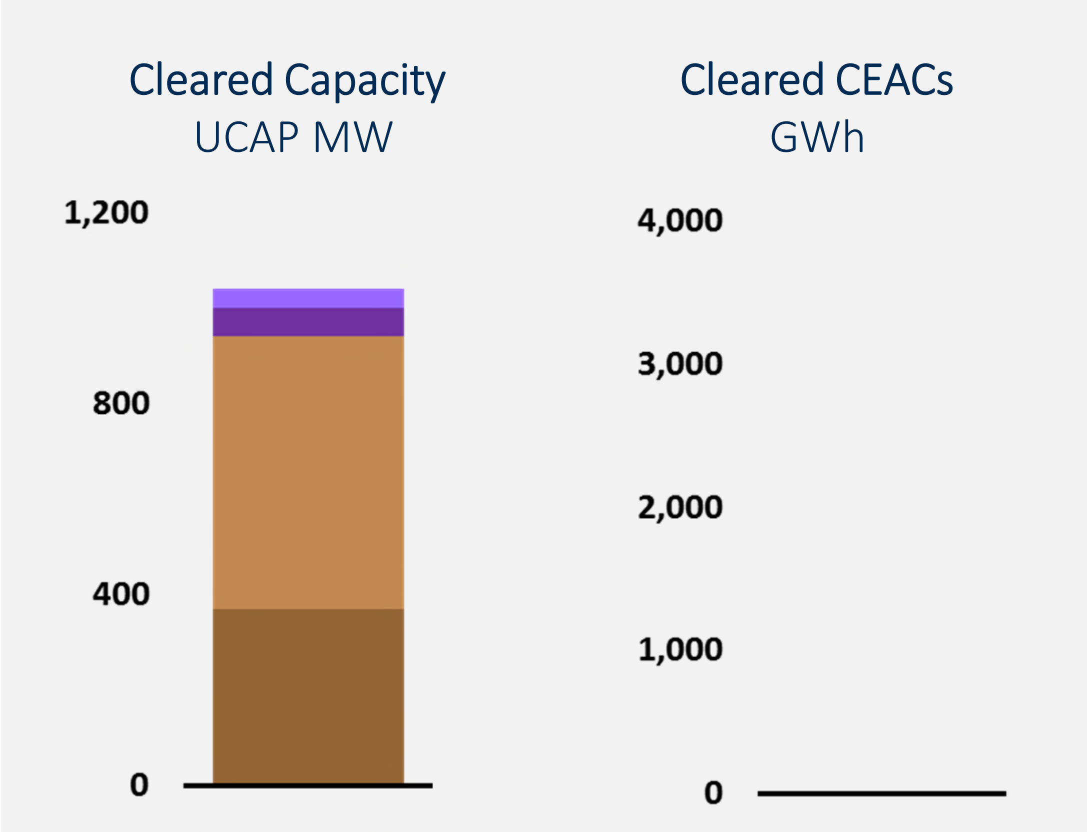




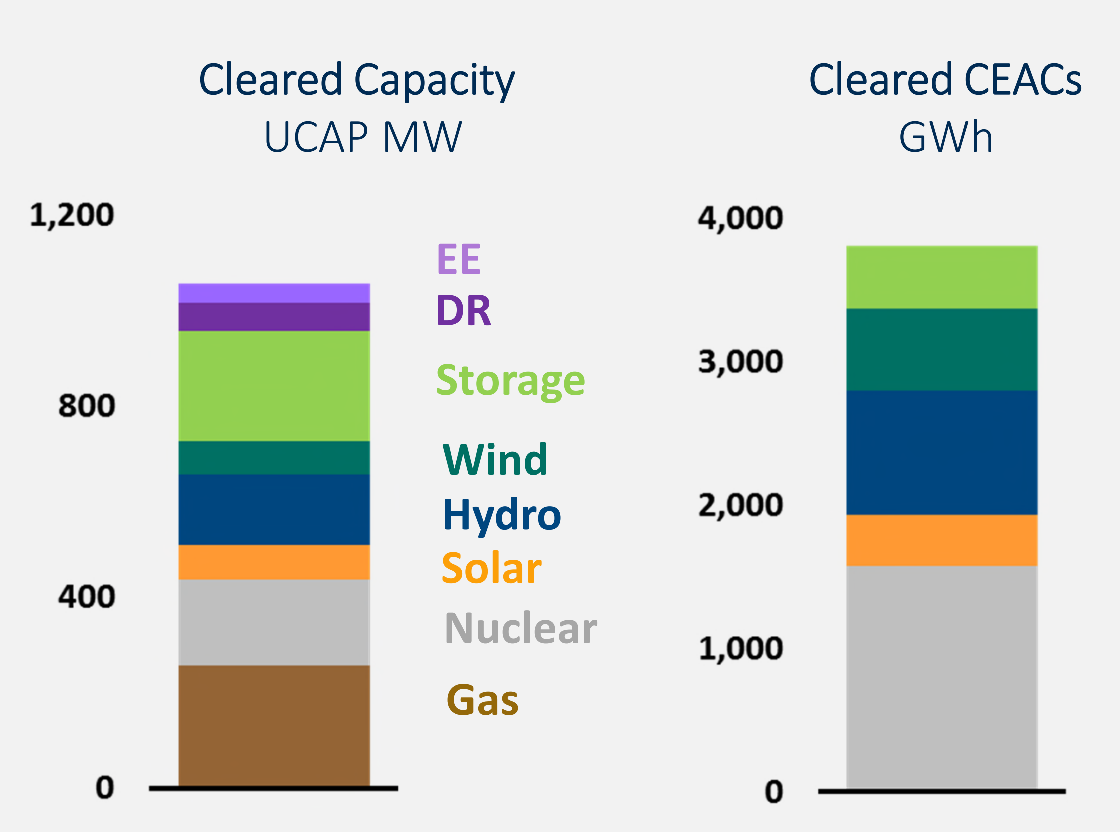
Note: Simplified example. Not intended to reflect New England.

What resources clear?

Traditional Capacity Market



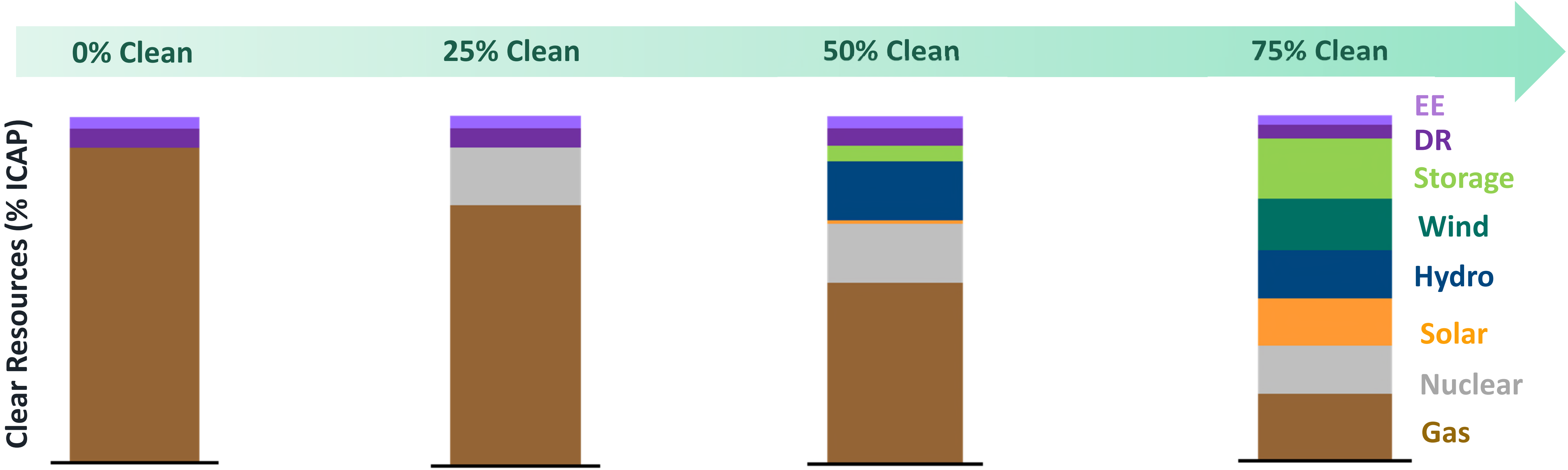
Integrated Clean Capacity Market



Note: Simplified example. Not intended to reflect New England.

How could an Integrated Clean Capacity Market guide the energy transition?

Extended simplified example illustrates the different resource mix cleared as the quantity of required CEACs increases*



*Simplified example is identical to prior slides other than the quantity of CEACs required. A full time series analysis would consider how offer prices and UCAP values change over time.

Pros and Cons

Advantages and challenges to consider if pursuing an Integrated Clean Capacity Market

Advantages

- Efficiency benefits of co-optimization
- Builds on demonstrated successes from the current capacity market (broad competition, ability to attract investment)
- Flexible framework can accommodate variety of state preferences & evolving reliability needs
- Offer states an in-market solution to meet policy
- Economically balance signals to attract new clean resources, retain flexible gas plants in transition, and prevent uneconomic oversupply of capacity

Challenges

- Complexity
- Requires states and ISO to work together
- Governance
- Transitional challenges to identify and mitigate near-term impacts on customers and existing resources

Appendix: Example Detail

APPENDIX

Example Detail: Integrated Clean Capacity Market Clearing

Resource Offers and Clearing

		Existing Gas	New Gas	Nuclear	Hydro	Solar	Onshore Wind	Offshore Wind	Storage	DR	EE
Offered Quantity											
ICAP	*(MW_N)*	400	800	200	200	200	300	300	250	60	40
UCAP	*(MW_C)*	368	733	180	150	70	96	135	230	60	40
CEACs	*(GWh/year)*	0	0	1,577	876	350	788	1,051	438	0	0
Offer Price	*($\$/kW\text{-}m_N$)*	$4.0	$5.5	$7.5	$8.0	$5.0	$7.0	$13.0	$8.0	$3.0	$2.0
Cleared Quantity											
ICAP	*(MW_N)*	371	0	200	200	200	300	0	129	60	40
UCAP	*(MW_C)*	341	0	180	150	70	96	0	119	60	40
CEACs	*(GWh/year)*	0	0	1,577	876	350	788	0	226	0	0
Percent Cleared	*(%)*	93%	0%	100%	100%	100%	100%	0%	52%	100%	100%
Revenues											
CEACs	*($M/year)*	$0	$0	$43	$24	$10	$22	$0	$6	$0	$0
Capacity	*($M/year)*	$18	$0	$9	$8	$4	$5	$0	$6	$3	$2
Total	*($M/year)*	$18	$0	$53	$32	$13	$27	$0	$12	$3	$2
Total	*($\$/kW\text{-}m_N$)*	$4	$0	$22	$13	$6	$7	$0	$8	$4	$4

ICAP = Installed capacity
UCAP = Unforced capacity
CEAC = Clean Energy Attribute Credit
N = Nameplate
C = Capacity rating

System-Wide Results

	Cleared Quantity	Offered Quantity	Clearing Price
Capacity	2,750 *(MW_N)*	1,500 *(MW_N)*	$4.3 *($\$/kW\text{-}m_N$)*
CEAC	5,081 *(GWh/year)*	3,817 *(GWh/year)*	$27.4 *($/MWh)*

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Dr. Kathleen Spees is a Principal at The Brattle Group with expertise in designing and analyzing wholesale electric markets and carbon policies. Dr. Spees has worked with market operators, transmission system operators, and regulators in more than a dozen jurisdictions globally to improve their market designs for capacity investments, scarcity and surplus event pricing, ancillary services, wind integration, and market seams. She has worked with U.S. and international regulators to design and evaluate policy alternatives for achieving resource adequacy, storage integration, carbon reduction, and other policy goals. For private clients, Dr. Spees provides strategic guidance, expert testimony, and analytical support in the context of regulatory proceedings, business decisions, investment due diligence, and litigation. Her work spans matters of carbon policy, environmental regulations, demand response, virtual trading, transmission rights, ancillary services, plant retirements, merchant transmission, renewables integration, hedging, and storage.

Dr. Spees earned her PhD in Engineering and Public Policy within the Carnegie Mellon Electricity Industry Center and her MS in Electrical and Computer Engineering from Carnegie Mellon University. She earned her BS in Physics and Mechanical Engineering from Iowa State University.

NEPOOL Participants Committee

Future Pathways

Round 1: Focus on Forward Clean Energy Market and Carbon Pricing:

Preliminary Observations and Request for Input

Frank A. Felder

October 1, 2020

Today's Presentation Will Cover

1. Overview: Purpose, Summary & Content, Pathways & Variations

2. Forward Clean Energy Market and Variations: Tradeoffs

   Break for Questions and Comments

3. Carbon Pricing: Tradeoffs

4. Next Steps:

   Questions, Comments, and Request for Input

5. Appendix: Abbreviations & References

Purpose of Project and Today's Presentation

Project Goal: By end of December, build a common understanding of Future Pathways by defining Pathways and their variations, describing key design variables, and analyzing tradeoffs among Pathways and Variations

1. Develop a common understanding of the Pathways and Variations
2. Analyze tradeoffs of Pathways (and Variations)
3. Receive input from stakeholders

OVERVIEW

1. **Overview**

   Context
   Clean Energy Investments and Their Linkages
   Retained ISO-NE Roles & Related Policies
   Pathways (identified to date; others may be proposed):
   - **Forward Clean Energy Market (FCEM)**
   - **Carbon Pricing (CP)**
   - **Energy Only Market (EOM)**
   - **Alternative Resource Adequacy Constructs (ARAC)**
   - **Integrated Clean Capacity Market (ICCM)**

2. Forward Clean Energy Market Pathway and Variations
3. Carbon Pricing Pathway and Variations
4. Next Steps
5. Appendix

Context: States Decarbonization with a Regional Grid and Markets

Presents preliminary observations on possible Pathways and initial request for input with focus on 2 Pathways

1. Presumes extensive and long-term effort to decarbonize the New England power sector and other energy sectors
2. Examines Pathways that have been proposed to integrate New England States' clean energy objectives with recognition that modifications to the region's wholesale market and power system may also require other changes
3. Compares Pathways across two key questions:
    1. Whether and to what extent the Pathway supports the clean energy policies of States?
    2. Whether and to what extent the Pathway garners efficiency of regional markets?

Pathways Retain ISO Functions and Their Success Depend on Many Other Polices

1. 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

2. 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

3. The outcomes of the Pathways depend on how they interact with the following:

   energy dispatch and curtailment, unit commitment, ancillary service definition and opportunity costs, imports and exports of power, bids and offers incentives, transmission planning and cost allocation, deployment of smart grid technologies, dynamic retail pricing, market monitoring and mitigation, wholesale and retail credit policies, and regional and State energy policies

Today’s Focus is on Two Pathways and Some of Their Variations

1. **Forward Clean Energy Market (FCEM)**
    1. **Numerous variations**

2. **Carbon Pricing (CP)**
    1. **With the RGGI framework (RGGI+)**
    2. **LMP carbon pricing in New England (LMP-C)**
    3. **Carbon pricing external to ISO-NE**

Today’s presentation focuses on FCEM & CP

3. Energy Only Market (EOM)

4. Alternative Resource Adequacy Constructs (ARAC)
    1. Fixed Resource Requirement (FRR)
    2. Regional Integrated Resource Planning (R-IRP)
    3. Others?

5. Integrated Clean Capacity Market (ICCM)

FORWARD CLEAN ENERGY MARKET (FCEM)

1. Overview
2. **Forward Clean Energy Market and Variations**

   FCEM Numerous Variations
   Regulatory-Market Tradeoffs

3. Carbon Pricing
4. Next Steps
5. Appendix

The FCEM Pathway Has Numerous Variations

FCEM Core Market Components

1. Unbundled Clean Energy Attribute Credit (CEAC): resource-neutral, uniform product, additional types of resources eligible than RECs
2. 3-year forward auction with 7-year commitment for new resources
3. Downward sloping demand curve
4. Bilateral and spot market trading

Major FCEM Market Design Variations

1. Static or dynamic CEAC
2. Demand curve anchored by social cost of carbon (SCC) or Clean Net CONE (CN-CONE)
3. Whether to allow targeted resource types
4. Whether FCEM is co-optimized with the ISO-NE FCM
5. Whether preexisting clean energy commitments are removed from the demand curve

Brattle, Sep. 2019. How States, Cities, and Customers Can Harness Competitive Markets to Meet Ambitious Carbon Goals Through a Forward Market for Clean Energy Attributes, Expanded Report Including Detailed Market Design Proposal, The Brattle Group

Regulatory-Market Tradeoffs of FCEM Variations

Regulators Set Quantities, Technologies & Timing ↔ Markets Set Prices

Vertical Integration

Integrated Resource Planning

FCEM Targeted Resources & Grandfathering

FCEM-CN-CONE & Static CEAC

FCEM-SCC & Dynamic CEAC

Carbon Pricing

1. The many FCEM variations are located at different places on the regulatory-market continuum
2. Fundamental tradeoff between imperfect regulation and imperfect markets

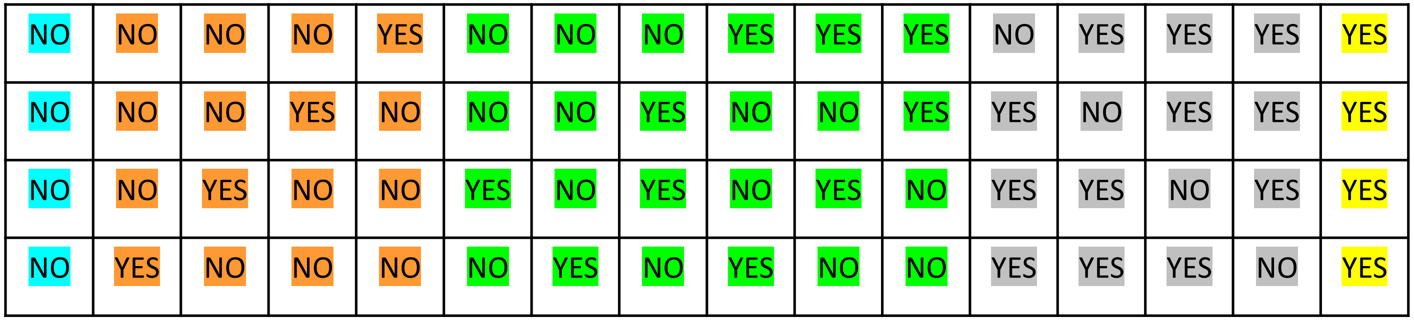
<u>Tradeoffs</u>

States have more control of outcomes	States have less control of outcomes
Ratepayers bear regulatory risk	Developers bear market risk
Lower cost of capital with longer financial guarantees	Lower costs due to technology flexibility and decreasing costs

There are Numerous FCEM Variations

Regulators Set Quantities,
Technologies & Timing

Markets
Set Prices



FCEM Design Choices																
Dynamic CEAC	NO	NO	NO	NO	YES	NO	NO	NO	YES	YES	YES	NO	YES	YES	YES	YES
Social Cost of Carbon	NO	NO	NO	YES	NO	NO	NO	YES	NO	NO	YES	YES	NO	YES	YES	YES
Base Resources - No Targeted Resources	NO	NO	YES	NO	NO	YES	NO	YES	NO	YES	NO	YES	YES	NO	YES	YES
No Pre-existing resource commitments	NO	YES	NO	NO	NO	NO	YES	NO	YES	NO	NO	YES	YES	YES	NO	YES

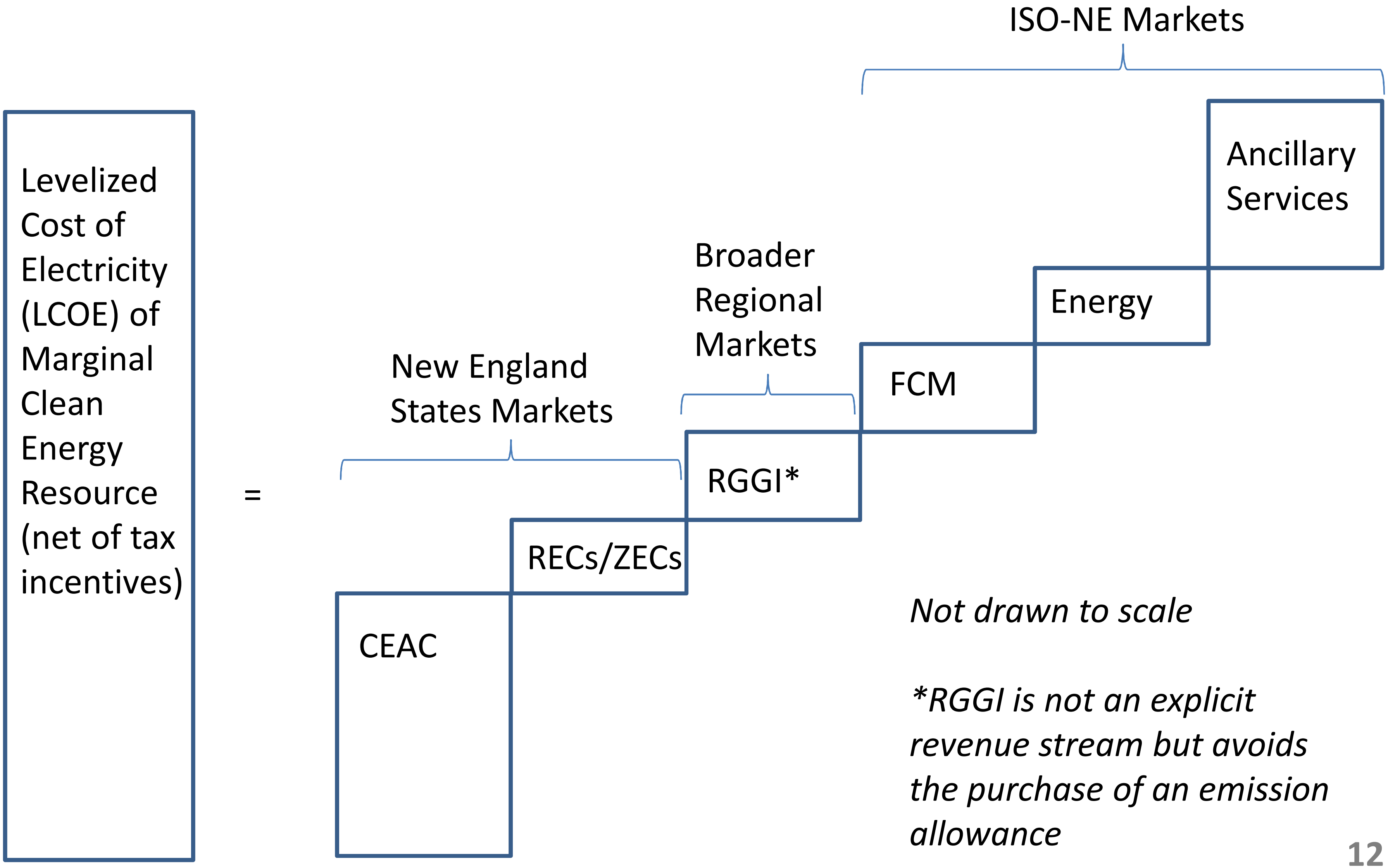
More likely to achieve
States specific
resource objectives

More likely to achieve
efficiency

Additional Observations

1. The States need to determine if they can agree on the key design features of a FCEM
2. Having multiple States' FCEMs would be administratively challenging
3. FCEMs impact on ancillary services requirements including whether FCEM resources can be curtailed should be considered
4. How the FCEM market is monitored and mitigated should be considered

FCEM Revenue Streams for Clean Energy Resources



Levelized Cost of Electricity (LCOE) of Marginal Clean Energy Resource (net of tax incentives)

=

CEAC

RECs/ZECs

RGGI*

FCM

Energy

Ancillary Services

New England States Markets

Broader Regional Markets

ISO-NE Markets

Not drawn to scale

**RGGI is not an explicit revenue stream but avoids the purchase of an emission allowance*

FCEM, Dynamic CEAC, SCC, No Targeted Resources

- Over time, revenue streams shift from ISO-NE markets to the New England States' FCEM
  - Single, region-wide CEAC price would likely provide major source of revenue for clean energy resources
  - RGGI allowance and energy prices decrease
  - If States retain RPS/RES, whether resources can sell both RECs and CEACs or only one of them affects if and how each of these markets clear and at what prices
- Dynamic CEAC likely incentivizes reduction of CO_2 emissions and development of energy storage
- Compared to Clean Net CONE (CN-CONE), using the social cost of carbon (SCC) to anchor the FCEM demand curve emphasizes efficient CO_2 emission reductions over specific amounts of reductions and particular resource technologies

FCEM, Dynamic CEAC, SCC, No Targeted Resources (con’t, 1)

- LCOE Marginal Adequacy Resource is likely combustion turbine (CT) recovering capital costs in FCM and operating costs in energy and ancillary service markets <u>or</u> energy storage recovering capital costs in FCEM and operating costs in energy and ancillary service markets
  - With large amounts of renewables, resource adequacy requirements may need to be set based upon satisfying demand over multiple cloudy, non-wind days (not unique to FCEM)
  - With large amounts of renewables, additional changes to the ancillary services markets may need to occur to ensure sufficient flexibility to balance supply and demand over various time steps
- Energy prices close to zero (but still have congestion and marginal loss components) but periodically spike to clear the energy market

FCEM, Dynamic CEAC, SCC, No Targeted Resources (con't, 2)

- If new clean energy resources procured via a FCEM do <u>not</u> clear the FCM due to a MOPR rule, then States will have achieved their clean energy resource goals but without garnering the financial value of resource adequacy that those resources provide, so called "double payment"
- If new clean energy resources procured via a FCEM clear the FCM because the FCEM provides them with additional cost recovery that would not have occurred but for the FCEM, then capacity and energy prices would be lower than without the FCEM, so called "price suppression"
  - An economic efficiency analysis of "price suppression" depends, in part, on the SCC
    - If SCC = 0, out-of-market payments inefficiently reduce prices
    - If SCC > 0 (which it is), then the combined efficiency impact of reducing emissions by using out-of-market payments while suppressing prices needs to be considered
  - A reliability analysis of "price suppression" depends, in part, whether changes to resource adequacy and ancillary services requirements and markets are necessary to account for the impact of substantial increases of renewable energy (same applies to CP)

FCEM Bookend Comparison

FCEM Structure	Clean Energy Investments	FCEM	FCM	Energy & Ancillary Services
Dynamic CEAC, SCC, No Targeted Resources	SCC may not be sufficient to achieve States' decarbonization goals or technological outcomes	Major source of revenue recovery for clean energy resources over time Multiple technologies compete to provide CEACs, lowering costs to satisfy demand	Price in FCM depends if marginal adequacy resource is CT or energy storage	Applies to both cases Energy prices are typically near zero with congestion and marginal loss components but periodically spike to clear the market Ancillary services Increase in importance to ensure sufficient flexibility to match supply and demand over multiple time scales Opportunity cost of providing ancillary services includes not producing a CEAC for qualifying resources
Static CEAC, Clean Net CONE, Targeted Technologies,	States achieve specific technology outcomes and carbon reduction goals	Dominant source of revenue FCEM has multiple tiers of pricing to accommodate targeted technologies at higher cost than without Non-competitive outcomes may result due too narrowly defined targets	Static CEAC does not support storage but FCEM targets may do so	

Co-optimizing FCEM with FCM

- In theory, co-optimizing would maximize the social surplus of meeting States' clean energy objectives and regions' resource adequacy requirements
- Not clear if can be implemented in practice*
- Without co-optimization, resources offering into the FCEM will have to estimate their expected revenues in the FCM and if those estimates are incorrect, inefficient outcomes may result
- The value of co-optimizing the FCEM with the FCM depends in part on the extent that resources in one can participate in the other; the less the overlap, the less the benefits that co-optimization provides

* ISO-NE, Jan. 2017, NEPOOL 2016 IMPAPP Proposals: Observations, Issues and Next Steps, http://nepool.com/uploads/IMAPP_20170125_ISO-NE_Discussion_Paper_Rev.pdf

Co-optimizing FCEM with FCM (con’t)

- If FCEM has multiple targeted resources, then the value that co-optimization provides is less because there is less flexibility across resources to co-optimize than without targeted resources
- If FCEM has multiple products, then co-optimization becomes more difficult, if at all, to implement
- If FCEM (or other pathways) fundamentally changes the location of generation resources on the grid compared to current resources, then the joint optimization/planning problem of generation and transmission becomes very important

BREAK FOR QUESTIONS AND COMMENTS

CARBON PRICING (CP)

1. Overview
2. Forward Clean Energy Market and Variations
3. **Carbon Pricing**

   CP Variations:
   - **RGGI**
   - **LMP-C**
   - **New England Carbon Pricing external to ISO-NE**
   - **Economic Efficiency vs State Energy Objectives**
   - **Administrative tradeoffs**

4. Next Steps
5. Appendix

CP* Variations

RGGI: Cap & Trade

1. Set emissions cap
2. Define and allocate emission allowances
3. Establish penalty for non-compliance
4. Allow for bilateral trading
5. RGGI has other offramp and banking policies that keep emission allowance prices within a bandwidth

LMP-C: Carbon Price

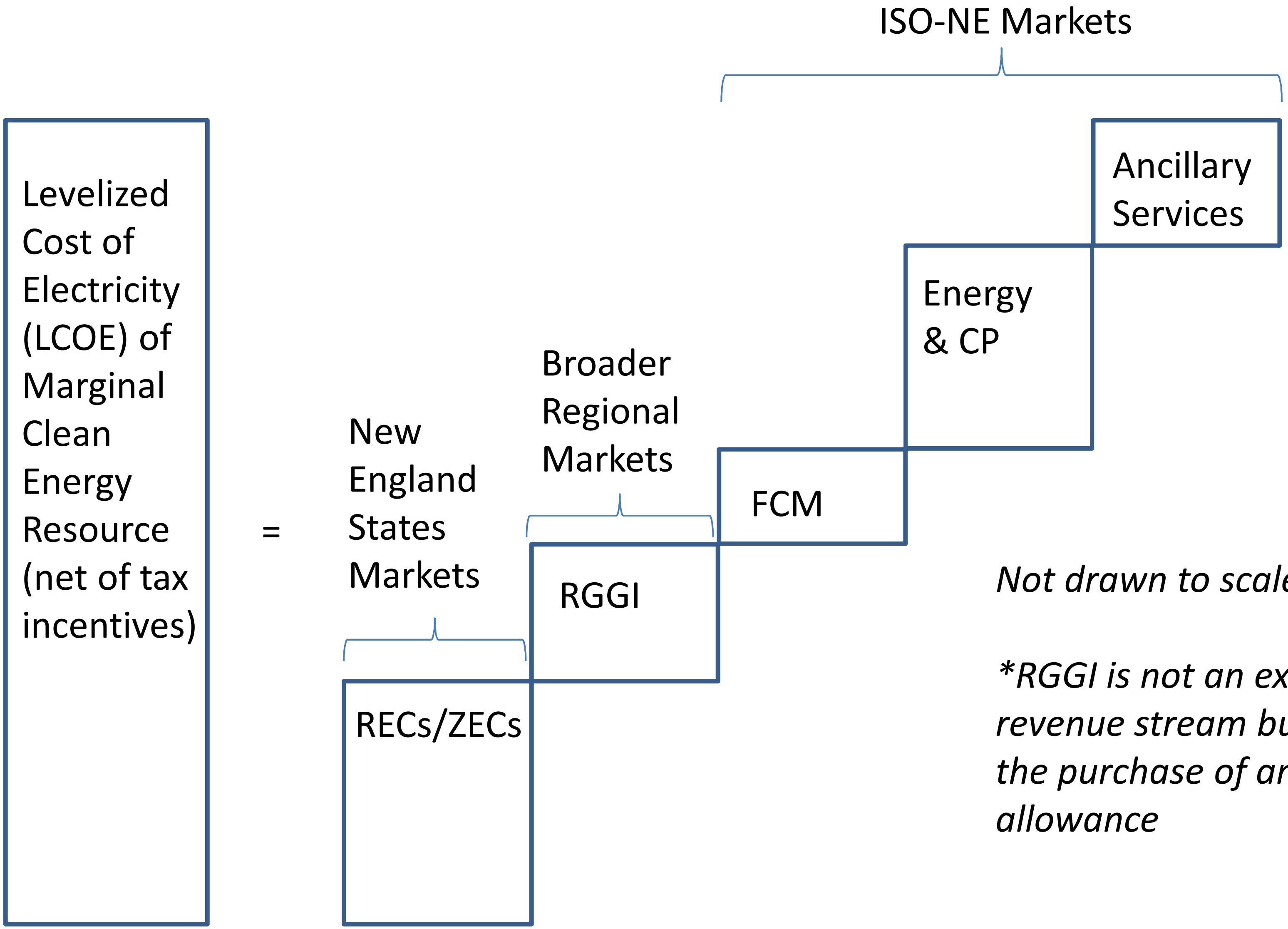
1. SCC is selected
2. ISO-NE administers carbon pricing as part of LMP
3. LMP-C nets out RGGI allowance cost (if done in conjunction with RGGI)
4. Revenues from LMP-C are allocated, e.g., to load

Carbon Tax External to ISO-NE

1. New England States select carbon tax
2. Carbon tax could account for RGGI allowance cost
3. New England States collect carbon tax from fuel suppliers and allocate revenues <u>or</u>
4. ISO-NE collects the tax from emitting generators

*Carbon pricing is used as a shorthand term for $/CO$_2$ ton, which accounts for the molecular weight of carbon dioxide

CP Revenue Streams for Clean Energy Resources



Not drawn to scale

**RGGI is not an explicit revenue stream but avoids the purchase of an emission allowance*

Some Observations on CP Variations

Regulators Set Quantities, Technologies and Timing ↔ Markets Set Prices

Vertical Integration

Integrated Resource Planning

FCEM Targeted Resources & Grandfathering

FCEM-CN-CONE & Static CEAC

FCEM-SCC & Dynamic CEAC

Carbon Pricing

1. CP approaches do not necessarily result in desired State outcomes, whether levels of CO_2 reductions or deployment of specific technologies, although States still could use RPS/RES to meet specific State clean energy goals (although may be subject to MOPR)
2. Compared to FCEM, CP is more economically efficient due to resource flexibility and using SCC

Some Observations on CP Variations (con't)

Regulators Set
Quantities and Technologies

Markets
Set Prices

Vertical Integration

Integrated Resource Planning

FCEM Targeted Resources & Grandfathering

FCEM-CN-CONE & Static CEAC

FCEM-SCC & Dynamic CEAC

Carbon Pricing

1. RGGI variation uses an existing, non-FERC jurisdictional organization
2. RGGI variation may require negotiations with non-New England States
3. LMP-C pricing would be FERC jurisdictional and require tariff changes
4. LMP-C with existing RGGI may be administratively cumbersome
5. The cost to finance resources depends, in part, on policy certainty, which depends on the Pathway and Variation but also on the underlying political jurisdiction and dynamics

CP-RGGI+ vs CP New England Alone (LMP-C or Tax)

- To achieve major CO_2 reductions, RGGI's emission cap must be substantially reduced so that prices of emission allowances are close to the SCC **(or substantial carbon price)**
- Energy prices increase in near to medium term, increasing the energy margins of low or non-emitting CO_2 resources
- With MOPR, low and non-emitting CO_2 resources decide if it is more profitable to sell RECs and not participate in the FCM, not sell RECs and participate in the FCM, or become economic in the FCM because their energy revenues increase so that the MOPR is not longer an impediment to clearing the FCM

CP-RGGI+ vs CP New England Alone (LMP-C or Tax)

- Low and non-emitting CO_2 resources offering into the FCM have larger energy margins and recover more of their fixed costs in the energy market enabling them to be more competitive in the FCM
- RGGI emission allowance prices increase under RGGI+, which may affect inter-ISO energy transfers (with likely more changes in energy transfers with CP New England Alone than with RGGI+)
- Less carbon leakage will occur with RGGI+ than with CP New England Alone

Additional Comparisons Between RGGI+ vs LMP-C or Carbon Tax

RGGI+

- Sets cap, so emission reductions (subject to RGGI offramp policies) are ensured
- If cap is too high, zero or small reductions occur
- If cap is too low, price of allowances is high (although allowance banking and resetting the cap can mitigate this)
- Requires agreement among RGGI States

LMP-C or Carbon Tax

- Sets carbon price so emission reductions are not guaranteed but the cost of the policy is capped
- If carbon price too low, low amounts of emission reductions occur
- If carbon price is too high, wholesale electricity prices rise more than necessary

NEXT STEPS

1. Overview
2. Forward Clean Energy Market and Variations
3. Carbon Pricing
4. **Next Steps**
5. Appendix

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, October 15 or sooner; all comments will be posted on the NEPOOL website

3. Preparation of similar presentation for Nov. 5 NEPOOL Participants Committee Meeting on preliminary observations on other identified Pathways: Energy Only Market, Alternative Resource Adequacy Constructs, Integrated Clean Capacity Market and possibly others

4. Additional presentation in December with goal to issue final report by end of the year, which will be circulated as a draft for comment

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

VOLL: Value of Lost Load

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