David T. Doot
Secretary

February 25, 2021

VIA ELECTRONIC MAIL

TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

RE: Supplemental Notice of March 4, 2021 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 March meeting of the Participants Committee will be held **via teleconference on *Thursday*, March 4, 2021, at 10:00 a.m.** for the purposes set forth on the attached agenda and posted with the meeting materials at nepool.com/meetings/. The dial-in number, to be used only by those who otherwise attend NEPOOL meetings and their approved guests, is **866-803-2146; Passcode: 7169224.**

For your information, the March 4 meeting will be recorded. NEPOOL meetings, while not public, are open to all NEPOOL Participants, their authorized representatives and, except as otherwise limited for discussions in executive session, consumer advocates that are not members, federal and state officials and guests whose attendance has been cleared with the Committee Chair. All those in attendance or participating 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.

Respectfully yours,

/s/
David T. Doot, Secretary

FINAL AGENDA

1. To approve the draft minutes of the February 4, 2021 Participants Committee meeting. The draft preliminary minutes of that meeting, marked to show changes from the draft circulated with the initial notice, are included with this supplemental notice and posted with the meeting materials.

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

3. To receive an ISO Chief Executive Officer report. Summaries of the ISO Board and Board Committee meetings that have occurred since the February 4 Participants Committee meeting are included with this supplemental notice and posted with the meeting materials.

4. To receive an ISO Chief Operating Officer report. The report will include a brief discussion of recent cold weather challenges outside of New England. The COO report will be circulated and posted in advance of the meeting. Background materials addressing ERCOT's recent experience are included with this supplemental notice and posted with the meeting materials.

5. To receive a presentation on the ISO Board candidate search process. Background materials will be circulated and posted in advance of the meeting.

6. To consider and take action, as appropriate, on proposed modifications to NEPOOL's previously-approved set of Offer Review Trigger Price (ORTP) values and related Tariff revisions (as well as consideration of the ISO's modified ORTP proposal). Background materials, including forms of resolutions for votes that may be taken at the meeting, are included with this supplemental notice and posted with the meeting materials.

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

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

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

9. Administrative matters.

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

    - Please note the memorandum from the Chair, which is included with this supplemental notice and posted with the meeting materials, concerning the NEPOOL process and rights relating to ISO audits and audit plans, together with an attachment from ISO Internal Audit.

PRELIMINARY

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held via teleconference beginning at 10:00 a.m. on Thursday, February 4, 2021. A quorum determined in accordance with the Second Restated NEPOOL Agreement was present and acting throughout the meeting. Attachment 1 identifies the members, alternates and temporary alternates who participated in the teleconference meeting.

Mr. David Cavanaugh, Chair, presided and Mr. David Doot, Secretary, recorded. Mr. Cavanaugh noted that the meeting would be divided into two sessions, a morning session addressing general business and an afternoon session, beginning at 1:00 p.m., focused on the threshold jurisdictional and legal issues associated with the potential pathways and alternative market frameworks.

APPROVAL OF JANUARY 7, 2021 MEETING MINUTES

Mr. Cavanaugh referred the Committee to the preliminary minutes of the January 7, 2021 meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of the January 7, 2021 meeting were unanimously approved as circulated, with an abstention by Mr. Michael Kuser's alternate noted.

CONSENT AGENDA

Mr. Cavanaugh referred the Committee to the Consent Agenda that was circulated and posted in advance of the meeting. Following motion duly made and seconded, the Consent Agenda was unanimously approved as circulated, with abstentions on behalf of the Conservation Law Foundation and Mr. Kuser recorded. Mr. Doot noted that the approval included support for revisions to Market Rule 1 to remove, as directed by the FERC's December 2, 2020 order issued in Docket No. EL20-54-000, the price-lock mechanism and zero-price offer rule from the

Forward Capacity Market (FCM), which had been filed a few days earlier by the ISO. He reported that NEPOOL would submit comments in support of the Market Rule revisions reflecting the Participants Committee's support for those changes.

JOINT NOMINATING COMMITTEE

In support of the ongoing efforts to enhance transparency with respect to the Joint Nominating Committee (JNC) process, Mr. Cavanaugh referred to the summary of the January 15 JNC meeting circulated in advance of this meeting. He highlighted the focus of the JNC on replacing the diversity, skills and expertise of the four directors that would be transitioning off the Board over the subsequent two years, including experience with financial and wholesale electric markets and transmission planning. In addition to these areas, the search would seek candidates with energy industry and cybersecurity experience, and focuses on consumer interests and the transition to a clean energy environment. Further, the JNC considered and agreed to evaluate all candidates without regard to the projected ability of such candidates at the outset to serve for the full contemplated term limit (three three-year terms) without the need for an age limit waiver, which could be addressed later as necessary and appropriate. He reported that the next JNC meeting would be held March 5. He also indicated that, as requested at the January Participants Committee meeting, the March 4 Participants Committee meeting would include a presentation on the Board candidate search process, including a list of the candidate qualifications being sought and for when, by a representative from Russell Reynolds Associates, the search firm working with the JNC.

Mr. Cavanaugh then introduced incumbent ISO Board Member Mr. Michael Curran, who would be completing his first three-year term later in the year and was being recommended for a second three-year term. Mr. Curran referred members to the overview of his background circulated in advance of the meeting. He then highlighted his experiences, including his roles as an ISO Board member, and summarized his vision for, and the ongoing challenges facing, the ISO Board and the region generally.

In response to questions from members, Mr. Curran noted the need to accommodate anticipated changes in technology and the importance of working collaboratively with ISO and industry colleagues through ongoing open communication, education and compromise. When asked about enhanced interaction with the Participants Committee, specifically beyond the stakeholder process, Mr. Curran referred to the current outreach process as beneficial and successful and encouraged continued effective use of those meetings. He noted that, should there be a need or opportunity for further interaction, that interaction should be on strategic issues at the time. He emphasized communication, education and compromise. In response to a question about ongoing Board transparency, Mr. Curran reflected on his past experience with open sessions in the Midcontinent Independent System Operator (MISO). He noted that the histories of the two regions working together were very different. New England's practice of twice-annual Sector meetings and individual meetings with each of the New England states were very positive features for New England in comparison to MISO. He noted that certain discussions of the MISO board were conducted in closed session. He explained that there were ongoing discussions of potential ways to enhance that transparency.

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 January 7, 2021 meeting, which had been circulated and posted in advance of the meeting. There were no questions or comments.

In response to a question at the prior meeting about the definition of "balancing resource" and a process for quantifying balancing resource requirements, Mr. van Welie suggested that balancing resources might not be defined in terms of technology types. Rather, he thought the preferred focus would be on defining system requirements for additional or balancing energy. He noted that this was among the areas of focus in the pathways studies and was subject to further discussions and clarification.

ISO COO REPORT

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), referred the Committee to his February report, which had been circulated and posted in advance of the meeting. He noted that the data in the report was through January 27 unless otherwise noted. The report highlighted: (i) Energy Market value for January 2021 was $354 million, down $96 million from an updated December 2020 value of $450 million and up $57 million from January 2020 (he noted that, with the extremely cold last four days of January, total energy market value was likely to approach $500 million, which he would identify more precisely in the March report); (ii) January 2021 average natural gas prices were 5.4 percent lower than December average prices; (iii) the average Real-Time Hub Locational Marginal Prices (LMPs) for January ($37.16/MWh) were 11 percent lower than December averages; (iv) average January 2021 natural gas prices and Real-Time Hub LMPs over the period were up 41 percent and up 42 percent, respectively, from January 2020 average prices; (v) the average Day-Ahead cleared physical energy during peak hours as percent of forecasted load was 98.4 percent during January (down from 98.5 percent during December), with the minimum value for the month (92.6 percent) on January 18; and (vi) the Daily Net Commitment Period Compensation (NCPC) payments for January (excluding the four cold days at the end of the month) totaled $3.1 million, which was down $0.5 million from December 2020 and up $1.3 million from January 2020. January NCPC through the 27th, which was 0.9 percent of total Energy Market value, was comprised of (a) $1.8 million in first contingency payments (down 0.1 million from December);

(b) $1.2 million in second contingency payments (down $403,000 from December); and (c) $72,000 in distribution payments (up $65,000 from December).

Turning to operational highlights from January, Dr. Chadalavada noted that the contingency costs were largely due to the outage of Line 391 (Scobie-Buxton), which had since returned to service. He reported that Line 385 (Deerfield-Buxton) would be out-of-service until the middle of following week and again later in the month for structure replacement, which was likely to result in similar second contingency costs. He estimated in response to a question that transfer limits between Maine and New Hampshire could be reduced by approximately 100-200 MWs, but the actual reductions would vary depending on flows from New Brunswick and the operations of generators in Maine. Dr. Chadalavada highlighted other expected major transmission line outages, including for Line 393/312 (Alps-Berkshire/Berkshire-Northfield) from February 17 through 19 and from March 1 through 20. He said that outage would be for the replacement of structures and the installation of phasor measurement units (PMUs), resulting in transfers between New York and New England, in both directions, being reduced to approximately 600-800 MW.

Mr. Chadalavada noted that -FCA15 would begin on February 8. A mock auction was run on February 1, with 165 representatives from 100 companies participating. No major issues were identified during the remotely-conducted four rounds, with minor connectivity issues resolved in real-time. He then noted that the future grid reliability study phase one work had begun, with related meetings to take place in February. Last, he announced that the 2021 Regional System Plan (RSP21) public meeting was scheduled for October 6, 2021, with the venue and meeting format yet to be finalized.

In response to a question regarding prices during the last few days of January, Dr. Chadalavada explained that, (i) as noted earlier in his report, natural gas prices averaged $11-

12/MMBtu, or roughly three times the average for the first two-thirds of the month; (ii) there was a few-day outage on a natural gas pipeline, which did not materially impact pipeline operations but did noticeably impact pricing and production on the energy side, and (iii) average loads were roughly 3,000 MW above the averages for the earlier part of the month. While each of these factors impacted pricing, the increases were most attributable to the higher gas prices. A member also noted that liquefied natural gas (LNG) prices in the international markets were very high so New England was more reliant on pipeline gas from Canada and domestic natural gas prices. Impacts were limited to pricing; there was no perceived risk to sufficiency of supply.

LITIGATION REPORT

Mr. Doot referred the Committee to the February 2 Litigation Report that had been circulated and posted in advance of the meeting. He then highlighted the following:

(1) ***Litigation on FCM Parameters*** – Since the January 6 Report, comments and protests on the changes filed by the ISO to update the Cost of New Entry (CONE), Net CONE, and Payment Performance Rate values, beginning with FCA16, had been submitted and were pending before the FERC;

(2) ***ARA ICR-Related Values and HQICCs*** - The FERC accepted on January 21 the Installed Capacity Requirement (ICR)-Related and Hydro Quebec Interconnection Capability Credits (HQICCs) values for the next round of Annual Reconfiguration Auctions (ARAs); and

(3) ***FCA15 Qualification Informational Filing*** - The FERC had accepted on January 22 the ISO's informational filing, directing the ISO to modify the FCA Qualified Capacity values for a couple of New Generating Capacity Resources.

COMMITTEE REPORTS

Markets Committee (MC). Mr. William Fowler, the MC Vice-Chair, reported that the next MC meeting would be held February 9-10. A special meeting was also scheduled for February 24 to vote on potential changes to the Offer Review Trigger Prices (ORTPs) as a result of tax law changes implemented after NEPOOL's vote on them but before they were filed.

Transmission Committee (TC). Mr. José Rotger, the TC Vice-Chair, reported that the TC would next meet on February 23. The agenda would include further discussion of the Participating Transmission Owners' proposal to address reconstitution of behind-the-meter generation into the Regional Network Load calculation, and a review of certain tariff and planning aspects of ISO compliance with Order 2222 (distributed energy resource aggregations in ISO/RTO markets).

Reliability Committee (RC). Mr. Robert Stein, the RC Vice-Chair, reported that the RC was scheduled to meet on February 16.

Joint MC/RC (Future Grid - Reliability Study). Mr. Stein also reported that the next joint meeting of the MC and RC was scheduled for February 25, but was likely to be re-scheduled to February 26 in light of a conflict with the States' New England Energy Vision technical session on governance reform.

Budget & Finance Subcommittee. Mr. Thomas Kaslow, the Subcommittee Chair, announced that the next meeting of the Subcommittee was scheduled for February 11 and would include a review of the ISO's quarterly capital funding tariff filing and year-end results for NEPOOL's budget. He reported that changes to the Non-Commercial Capacity trading financial assurance provisions of the Financial Assurance Policy would next be discussed at the Subcommittee's March 25 meeting.

ADDITIONAL MATTERS

Mr. Cavanaugh referred the Committee to a memo from a Participant representative, Mr. William P. Short III, circulated with the materials for the meeting, regarding a study of the issue of compensation for NEPOOL officers. He noted the request in the memo that Participants provide feedback to Mr. Short and encouraged those amenable to provide such feedback by May 1, 2021, as requested.

ADMINISTRATIVE MATTERS

Mr. Doot reminded the Committee of two upcoming meetings: a working session of the Participants Committee on February 18 to discuss the ISO's proposed analysis of certain potential pathways/market frameworks; and the March 4 meeting, which would likely include a vote on revisions to ORTP values/provisions supported by the Participants Committee at its December 4 meeting.

Ms. Heather Hunt, NESCOE Executive Director, noted that the New England Energy Vision technical sessions on wholesale market design and transmission planning had been held. Recordings and presentations for those sessions were posted on the New England Energy Vision website. A technical session on governance reform was scheduled for February 25, 9-2 p.m.; registration for that session was open. An incremental evening session on environmental justice-related matters would also be held, with details not yet finalized. Finally, in connection with the pathways study process, NESCOE sent a request to the ISO to provide a centralized summary of all the on-going studies that were underway and a website location for any future updates. In response to a question, Ms. Hunt committed to ensure that the contemplated report to the New England governors and any other output that might follow from the technical session process would be made available as part of the future pathways process underway.

PATHWAYS TO THE FUTURE GRID: LEGAL AND JURISDICTIONAL ISSUES

After a brief recess, the meeting resumed via WebEx. Mr. Doot referred the Committee to, and proceeded to review, a background presentation that had been circulated and posted in advance of the meeting on the threshold jurisdictional/legal issues associated with the potential pathways/alternative market frameworks. His presentation highlighted that the FERC's jurisdictional authority is set forth and limited by the Federal Power Act (FPA) to the transmission of energy in interstate commerce and the sale of energy at wholesale in interstate commerce. He explained that sections 205 and 206 of the FPA require the FERC to ensure that wholesale rates be filed with it and be just and reasonable and not unduly discriminatory or preferential. ~~The~~ FPA section 201(b) reserves to the states jurisdiction over retail electric power sales, distribution, generation siting and everything that does not otherwise fall within federal jurisdiction.

Mr. Doot then reviewed from his presentation several relevant court cases interpreting those provisions of the FPA. To help explain the concepts, he grouped factual circumstances into categories where current precedent have upheld FERC jurisdiction (thereby giving FERC a green light to act), those in which Courts have found FERC does not have jurisdiction (a red light) and those in which it is unclear whether FERC has jurisdiction (a yellow light).

Finally, he summarized in his presentation the precedent that helped to inform the FERC's evaluation of whether proposals presented to it are "just and reasonable and not unduly discriminatory or preferential." He briefly explained the *Mobile-Sierra* doctrine that presumes ~~that~~ rates set in freely negotiated contracts to be just and reasonable unless those contracts harm the public interest. Addressing what is needed t~~T~~o demonstrate that a proposed rate is not unduly discriminatory, Mr. Doot summarized precedent that permits differences in rates, terms, and conditions so long as the differences are properly justified. Absent proper justification for such differences, the FERC and courts will likely conclude that the rates are unduly discriminatory or preferential. He highlighted in the presentation several recent cases in which FERC addressed the issue of undue discrimination.

Mr. Cavanaugh then introduced Tony Clark, former FERC Commissioner, who moderated a panel discussion on legal and FERC-jurisdictional issues that may face future grid proposals. He introduced the following panelists (who were not speaking on behalf of any particular client or Entity):

- Phyllis Kimmel, an attorney in solo practice who had previously represented, among others, NESCOE and numerous state agencies and authorities on market and jurisdictional issues before the FERC and the US Court of Appeals for the DC Circuit;
- Ari Peskoe, Director of the Electricity Law Initiative at the Harvard Law School Environmental and Energy Law Program, who has written extensively about electricity regulation and was a presenter at the FERC's carbon pricing conference; and
- John Estes, the head of Skadden's Energy Regulation and Litigation Group, who had previously represented a group of generators in the protracted LICAP litigation, and as well as in FERC litigation involving numerous entities with conventional resources in New England.

The panel discussion focused on three main themes: (1) the issue of undue discrimination; (2) the interplay between state and federal jurisdiction; and (3) the protections that might be available under the *Mobile-Sierra* doctrine.

Mr. Clark began by asking the panelists for their thoughts on the *Mobile-Sierra* doctrine, and whether a state agreement about one of the future grid initiatives, such as a carbon price, might be afforded *Mobile-Sierra* protection (under which it would be more difficult to overturn a freely negotiated contract). While there was general agreement that ~~*Mobile*~~ *Mobile-Sierra* provides a freely negotiated agreement some protection from being overturned, that protection was not absolute and could be challenged if the agreement was not in the public interest. Further, the genesis of the doctrine was over bilateral contracts negotiated at arm's length, and it was not certain the extent to which *Mobile-Sierra* would be applied to a market design construct or other type of future grid initiative. A panelist noted that courts have given the FERC leeway to apply *Mobile-Sierra* in other contexts, but is not clear how the FERC or courts would apply that doctrine to arrangements negotiated with the states. Given the likelihood that any FERC consideration of broad-based measures to reduce carbon will be considered by courts on appeal, the *Mobile-Sierra* ~~court~~ precedent, should it be found to apply, could ~~will~~ provide some protection against involuntary changes required by the FERC.

Mr. Clark then asked the panel for their insights on the middle ground between state jurisdiction and federal jurisdiction and what tools could be used to allow jurisdiction under both. The panelists agreed that forums like NEPOOL provide~~d~~ an excellent opportunity for middle ground collaboration between federal and state entities. The panelists also agreed that the FERC would have to be open to working with the states, and noted the latest composition of the Commission could facilitate that collaboration. The panelists discussed the idea of a "joint board" between the states and the FERC, citing the success of a similar structure in the telecommunications industry, although such a structure necessarily requires the cooperation of the FERC. The panelists also discussed the possibility of a Memorandum of Understanding (MOU) among ISO and the states, concluding generally that a MOU ~~w~~could provide some limited protection against involuntary change required by the FERC, although that kind of protection would certainly not be absolute.

The panelists then discussed the topic of a Minimum Offer Price Rule (MOPR). There was generally the sense that, even if~~though~~ FERC may have a valid jurisdictional basis for the MOPR, it would not be surprising if the new Commission withdraws future support for the MOPR. One panelist noted that, while MOPRs may have served a purpose to protect against buyer-side market power, in practice they are interfering with state policies. Another panelist suggested that FERC may be advancing its policy goals to the detriment of the state policies on renewables that are within the states' statutory authority.

The panelists explored at high level the question of whether one or more of the future grid proposals, such as a Forward Clean Energy Market (FCEM), might eliminate the need for a MOPR. That discussion was not definitive but instead highlighted the legal and policy goals of a MOPR and the possibility that certain of the proposals might obviate the need for a MOPR to advance those goals.

The panelists discussed the issues surrounding carbon pricing. The panelists had different views on this topic. One panelist opined that FERC's regulation of carbon pricing was plausible, feasible and defensible if it was demonstrably desirable to improve the efficiency and competitiveness of the wholesale market. The other panelists both opined that the courts, and not the FERC, will determine the FERC's authority to regulate carbon prices absent change in the FERC's statutory authority. One panelist expressed the view that the more expedient solution would be for the states to impose a price on carbon.

Turning to the issue of undue discrimination, the panelists agreed that any distinction among resources would need to be supported by valid reasons for treating the resources differently. The panelists suggested that a state law requiring utilities to buy from renewable resources could establish a valid, and not unduly discriminatory, distinction. However, there were examples of the FERC rejecting the notion that state policy was a valid distinction. Acknowledging precedent cutting both ways, the panelists agreed that the new Commission was likely situated to re-write this precedent and that this issue was ripe for FERC consideration.

Finally, the panelists were invited to offer parting words of advice for the region as it proceeds to consider future grid proposals. One panelist suggested a focus on legal jurisdiction, suggesting that FCEM, for example, might be designed to be outside FERC jurisdiction. Where such jurisdiction rests with the FERC, the region would need to work together to demonstrate that the proposal meets the just and reasonable standard. Another panelist reiterated the view that a state-imposed carbon tax would be among the most straight-forward options. The third panelist emphasized the importance on following a process of informed, collaborative discussion among all affected parties and with the FERC before decisions are made.

In response to members' questions, panelists suggested that the best way to avoid a finding of undue discrimination would be to establish a well-developed record with evidence supporting differential treatment. The panelists characterized MOPR as a matter of FERC policy and predicted that the new Commission was likely to scale back its scope. They agreed that the FERC would likely be open to alternative market constructs that eliminate or reduce the need for a MOPR, so long as those constructs avoid price suppression and produce just and reasonable rates. On the issue of states' ability to contract independently, panelists concurred that the FPA did not restrict states from contracting with resources or entering into bilateral contracts, and explored the possibility of quasi-~~S~~section 205 filing rights for states/state commissions. Noting certain analogous examples, panelists identified practical limitations to the establishment of more traditional filing rights, suggesting, and discussing the advantages and limitations of, other tools to enhance stakeholder, state and federal regulator collaboration.

There being no further business, the meeting adjourned at 4:04 p.m.

Respectfully submitted,

David Doot, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN FEBRUARY 4, 2021 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Acadia Center	End User	Deborah Donovan		
Advanced Energy Economy	Fuels Industry Participant	Caitlin Marquis	Jeff Dennis	
American Petroleum Institute	Fuels Industry Participant	Paul Powers		
American PowerNet Management	Supplier			Joyceline Chow
AR Large Renewable Generation (RG) Group Member	AR-RG	Alex Worsley		
AR Small Load Response (LR) Group Member	AR-LR	Brad Swalwell		Doug Hurley
AR Small RG Group Member	AR-RG	Erik Abend		
Ashburnham Municipal Light Plant	Publicly Owned Entity		Brian Thomson	
Associated Industries of Massachusetts (AIM)	End User		Bob Ruddock	Roger Borghesani; Joyceline Chow
AVANGRID: CMP/UI	Transmission		Alan Trotta	
Avangrid Renewables	Transmission	Kevin Kilgallen		
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
Borrego Solar Systems Inc.	AR-DG	Liz Delaney		
Boylston Municipal Light Department	Publicly Owned Entity		Brian Thomson	
BP Energy Company	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity			Dave Cavanaugh
Brookfield Renewable Trading and Marketing	Supplier	Aleks Mitreski		
Calpine Energy Services, LP	Supplier	Brett Kruse		Bill Fowler
Castleton Commodities Merchant Trading	Supplier			Bob Stein
Central Rivers Power	AR-RG		Dan Allegretti	
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
CLEAResult Consulting, Inc.	AR-DG	Tamera Oldfield		
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		
CPV Towantic, LLC	Generation	Joel Gordon		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Dominion Energy Generation Marketing, Inc.	Generation		Weezie Nuara	
DTE Energy Trading, Inc.	Supplier			José Rotger
Dynegy Marketing and Trade, LLC	Supplier	Andy Weinstein		Bill Fowler
Emera Energy Services	Supplier			Bill Fowler
Enel X North America, Inc.	AR-LR	Michael Macrae		
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Environmental Defense Fund	End User	Jolette Westbrook		
Eversource Energy	Transmission	James Daly	Dave Burnham	
Excelerate Energy LP	Fuels Industry Participant	Gary Ritter		
Exelon Generation Company	Supplier	Steve Kirk	Bill Fowler	
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc.	Supplier	José Rotger		
Generation Group Member	Generation	Dennis Duffy	Abby Krich	Alex Worsley
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Great River Hydro	AR-RG			Bill Fowler
Groton Electric Light Department	Publicly Owned Entity		Brian Thomson	

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN FEBRUARY 4, 2021 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 Guilbault	Bob Stein	
Harvard Dedicated Energy Limited	End User	Joyceline Chow		
High Liner Foods (USA) Incorporated	End User		William P. Short III	
Hingham Municipal Lighting Plant	Publicly Owned Entity	John Coyle	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	Alan Topalian		
Interstate Gas Supply, Inc.	Supplier		Scott Hendricks	
Ipswich Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Jericho Power LLC (Jericho)	AR-RG	Mark Spencer	Nancy Chafetz	Herb Healy; Marji Philips
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	Alan Topalian		
Mansfield Municipal Electric Department	Publicly Owned Entity		Brian Thomson	
Maple Energy LLC	AR-LR			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	Rebecca 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		Jason York	
Middleborough Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Middleton Municipal Electric Department	Publicly Owned Entity		Dave Cavanaugh	
National Grid	Transmission		Tim Martin	
Natural Resources Defense Council	End User	Bruce Ho		
Nautilus Power, LLC	Generation		Bill Fowler	
New Hampshire Electric Cooperative	Publicly Owned Entity	Steve Kaminski		Brian. Forshaw; Dave Cavanaugh; Brian Thomson
New Hampshire Office of Consumer Advocate (NHOCA)	End User		Erin Camp	
NextEra Energy Resources, LLC	Generation	Michelle Gardner		
North Attleborough Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Norwood Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
NRG Power Marketing LLC	Generation		Pete Fuller	
Pascoag Utility District	Publicly Owned Entity		Dave Cavanaugh	
Paxton Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Peabody Municipal Light Department	Publicly Owned Entity		Brian Thomson	
PowerOptions, Inc.	End User			Erin Camp
Princeton Municipal Light Department	Publicly Owned Entity		Brian Thomson	
PSEG Energy Resources & Trade LLC	Supplier		Eric Stallings	
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Rodan Energy Solutions (USA) Inc.	Provisional Member	Aaron Breidenbaugh		
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN FEBRUARY 4, 2021 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	
Sterling Municipal Electric Light Department	Publicly Owned Entity		Brian Thomson	
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Sunrun Inc.	AR-DG			Pete Fuller
Taunton Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
The Energy Consortium	End User	Roger Borghesani	Mary Smith	Joyceline Chow
Vermont Electric Cooperative	Publicly Owned Entity	Craig Kieny		
Vermont Electric Power Co. (VELCO)	Transmission	Frank Ettori		
Vermont Energy Investment Corp (VEIC)	AR-LR		Doug Hurley	
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wakefield Municipal Gas & Light Department	Publicly Owned Entity		Brian Thomson	
Wallingford DPU Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
West Boylston Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wheelabrator North Andover Inc.	AR-RG		Bill Fowler	

CONSENT AGENDA

Reliability Committee (RC)

From the previously-circulated notice of actions of the RC's February 16, 2021 meeting, dated February 17, 2021[1].

1. Changes to OP-11 Appendix F (Satellite Phone Clarifications to Communications Verification Data)

Support changes to Appendix F to ISO New England Operating Procedure (OP) No. 11 (Instructions for Completing the Designated Blackstart Resource Testing Log) to clarify the specifications for satellite phone test in communication verification, as recommended by the RC at its February 16, 2021 meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

The motion to recommend Participants Committee support was unanimously approved.

2. Changes to OP-12 Appendix D (Biennial Review)

Support changes to Appendix D to OP-12 (Voltage Schedule Annual Transmittal Form) that, following a biennial review, include streamlined instructions and notice only to Option C Generator Assets (Exempt from Voltage Control) that 2021 is the final year this classification of assets will be required to provide a voltage schedule transmittal, all as recommended by the RC at its February 16, 2021 meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

The motion to recommend Participants Committee support was unanimously approved.

3. Changes to OP-4 and OP-4 Appendix A (Annual Review)

Support revisions to OP-4 (Actions During a Capacity Deficiency) and Appendix A to OP-4 (Estimates of Additional Generation and Load Relief from System Wide Implementation of Actions in OP-4 Based on a 25,000 MW System Load) that, following an annual review, include edits to conform the procedure to NPCC Directory #5 and clarifications to the description of expected MW relief from voltage reduction in Actions 6 and 8, as recommended by the RC at its February 16, 2021 meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

The motion to recommend Participants Committee support was unanimously approved.

4. Changes to OP-14 and OP-14 Appendices F, H and I (Solar Data Requirements Project Conforming Changes)

Support revisions to OP-14 (Technical Requirements for Generators, Demand Response Resources, Asset Related Demands and Alternative Technology Regulation Resources) and OP-14 Appendices F (), H () and I (), including details for new solar Generator Asset data requirements and conforming changes for existing wind Generator Asset data associated with pending Tariff changes, clarifications to existing wind Generator Asset and Continuous Storage Facility telemetry requirements, updates to RTU-related language, and clean-up, all as recommended by the RC at its February 16, 2021 meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

The motion to recommend Participants Committee support was unanimously approved.

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

Markets Committee (MC)

From the previously-circulated notice of actions of the MC's February 9-10, 2021 meeting, dated February 10, 2021.[2]

5. Changes to Market Rule 1 to List All IMM Ethics Standards Directly in Tariff and to Remove the ISO's Code of Conduct as an Attachment to the Tariff

Support (i) revisions to Sections III.A.18.1 and Exhibit 5 of Market Rule 1 to list all the IMM minimum ethics standards directly in the Tariff and (ii) to no longer attach to the Tariff the ISO's Code of Conduct, as recommended by the MC at its February 9-10, 2021 meeting, together with such further non-material changes as the Chair and Vice-Chair of the MC may approve.

The motion to recommend Participants Committee support was approved unanimously.

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

Summary of ISO New England Board and Committee Meetings

March 4, 2021 Participants Committee Meeting

Since the last update, the Compensation and Human Resources Committee met on February 8. The Nominating and Governance Committee, the Audit and Finance Committee, and the Board of Directors each met on February 18. All of the meetings were held virtually.

The Compensation and Human Resources Committee convened in executive session and discussed the Company's corporate performance for 2020 and officer compensation for 2021.

The Nominating and Governance Committee discussed the Company's annual communications and outreach plan. The Committee also considered topics for discussion with the Board's meeting with state representatives in March.

The Audit and Finance Committee met with the Company's investment advisors for the Company's benefits plan assets and 401(k) plan and received an analysis of investment options and details regarding the mix, cost, and performance of plan investments. The Committee approved fund changes recommended by the investment advisors. The Committee also approved significant accounting estimates used in the Company's budgeting and financial statements, including earnings and discount rates, health care trends, and depreciation. Finally, the Committee met in executive session to review Internal Audit Department results for 2020 and considered the performance and 2021 compensation for the Director of Internal Audit.

The Board of Directors convened in executive session and approved the corporate performance results for 2020 and officer compensation for 2021. In regular session, the Board received reports from the standing committees. During the Nominating and Governance Committee report, the Board approved the creation of a new standing committee, the Information Technology and Cyber Security Committee, and approved the new committee members and chair as follows:

- Ms. VanZandt and Messrs. Colangelo, Curran and Vannoy, with Mr. Colangelo to serve as Chair.

The Board also reviewed the Company's strategic planning process for 2021, received an update on developments at FERC, the states and Congress, and discussed various director education initiatives. In addition, the Board discussed recent state liaison meetings and the upcoming March meeting with NECPUC, and plans for the upcoming ISO/RTO Council Board Meeting in May.

NEPOOL Participants Committee Report

March 2021

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

Regular Operations Report - Highlights

Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Update: January 2020 Energy Market value totaled $488M
  - February 2021 Energy market value over the period was $716M, up $228M from January and up $483M from February 2020
  - February 2021 natural gas prices over the period were 92% higher than January average values
    - Average RT Hub Locational Marginal Prices ($77.42/MWh) were 77% higher than January averages
      - DA Hub: $80.15/MWh
    - Average February 2021 natural gas prices and RT Hub LMPs were up 320% and 281%, respectively, from February 2020 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 99.2% during February, up from 98.4% during January*
    - The minimum value for the month was 94.4% on Monday, February 1st

Data through February 24th

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

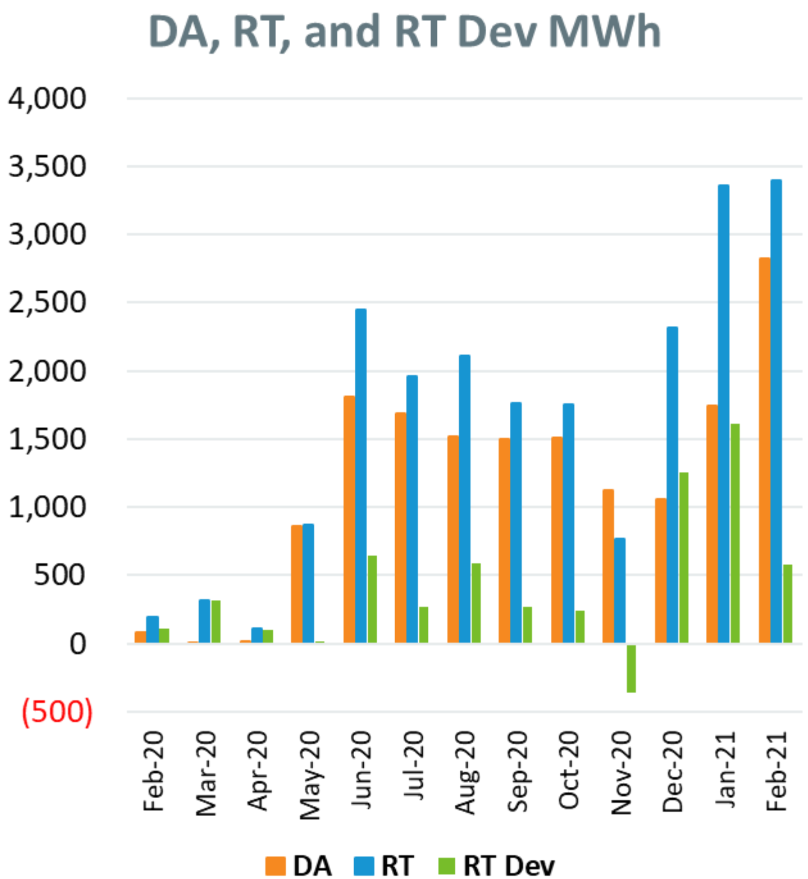
*DA Cleared Physical Energy is the sum of Generation and Net Imports cleared in the DA Energy Market

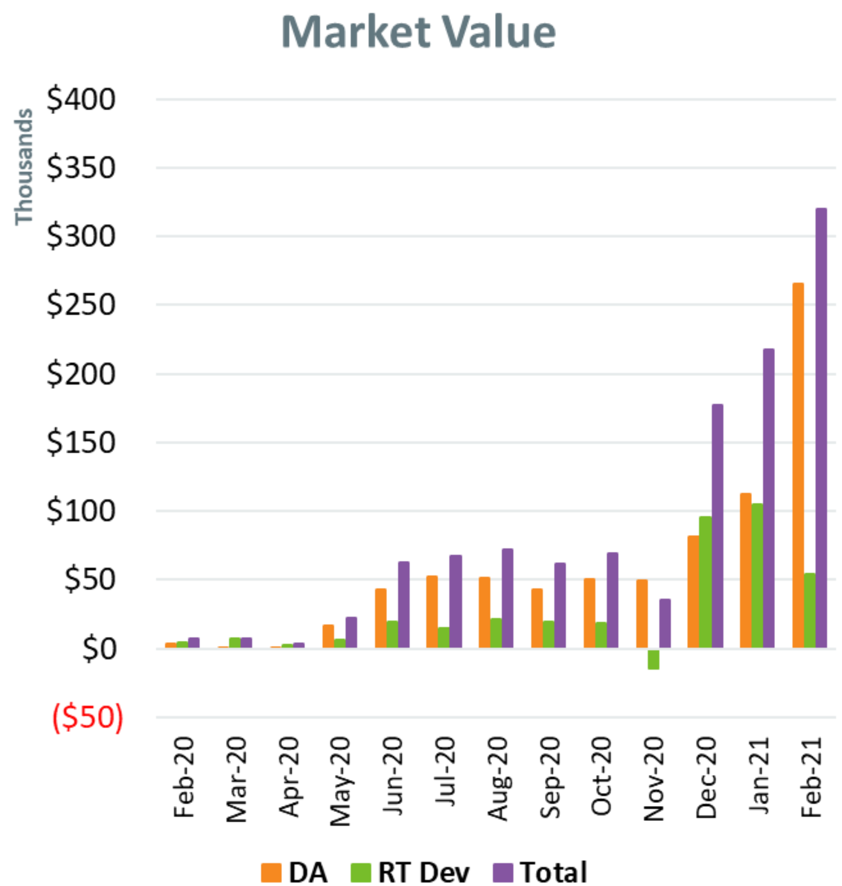
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - February NCPC payments totaled $2.3M over the period, down $1.2M from January and up $1.3M from February 2020
    - First Contingency payments totaled $1.9M, down $0.2M from January
      - $1.9M paid to internal resources, up $0.1M from January
        - » $596K charged to DALO, $655K to RT Deviations, $649K to RTLO*
      - $16K paid to resources at external locations, down $275K from January
        - » Charged to RT Deviations
    - Second Contingency payments totaled $0.1M, down $1.1M from January
    - Distribution payments totaled $259K, up $134K from January
    - Voltage payments were zero
  - NCPC payments over the period as percent of Energy Market value were 0.3%

* NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $272K; Rapid Response Pricing (RRP) Opportunity Cost - $323K; Posturing - $31K; Generator Performance Auditing (GPA) - $23K

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 12 (2021-2022)
  - Third and final annual reconfiguration auction (ARA3) will be held on March 1-3, and results will be posted no later than March 31
- CCP 13 (2022-2023)
  - Second annual reconfiguration auction (ARA2) will be held on August 2-4, and results will be posted no later than September 1
- CCP 14 (2023-2024)
  - First annual reconfiguration auction (ARA1) will be held on June 1-3, and results will be posted no later than July 1
- CCP 15 (2024-2025)
  - Auction results were filed with FERC on February 26

CCP – Capacity Commitment Period

FCM Highlights, cont.

- CCP 16 (2025-2026)
  - The qualification process has started, and training materials are under development
  - Topology certifications were sent to the TOs on October 1, 2020
    - Approved projects were shared with the RC at their January meeting
  - Capacity zone development discussions began at the November 19, 2020 PAC meeting
    - All subsequent reconfiguration auctions model the same zones as the FCA
  - FCA 16 dynamic delist bid threshold price to be determined, then posted to the ISO-NE website in early March upon FERC approval of the new methodology

Highlights

- FCA 15 was completed on February 8, and results were filed with the FERC on February 26
- Draft 2019 Electric Generator Air Emissions Report results were presented to the Environmental Advisory Group on February 19
- 2021 first quarter CO_2 emissions are trending higher than first quarter emissions from previous years
- Efforts to finalize the Future Grid Reliability Study (FGRS) Phase 1 study assumptions continue
- 2021 Economic Study requests are due April 1
- 2021 load forecast nearing completion and will be published as part of the CELT report on April 30
- Transmission Planning for the Clean-Energy Transition study results are expected in Q2

Load Forecast

- Efforts continue to enhance load forecast models and tools to improve day-ahead and long-term load forecast performance
- The 2021 load forecast development process continues
  - Upcoming meetings include: Energy-Efficiency Forecast Working Group (3/19), Load Forecast Committee (3/26), and Distributed Generation Forecast Working Group (3/22)
  - Changes to reconstitution used in the gross load forecast have required fundamental changes to be developed and implemented into the 2021 energy-efficiency forecast
  - In the March/April timeframe, PAC and RC will discuss the preliminary ten-year forecast
  - Publication of the final ten-year forecast will be in the CELT report, which will be posted on April 30

FERC Order 1000

- Qualified Transmission Project Sponsor (QTPS)
  - 25 companies have achieved QTPS status
  - 2021 Annual QTPS Certification
    - All 25 QTPSs submitted completed Annual QTPS Certification forms to the ISO prior to the close of the Certification Window on January 31
    - The ISO has determined that all 25 QTPSs continue to meet the Attachment K requirements and has notified them accordingly
- The Boston 2028 RFP lessons-learned process, with respect to competitive transmission solutions, was discussed at the 12/16/20 PAC meeting, and initial ISO responses were discussed at the 2/17/21 PAC meeting
  - Further discussion will continue at future 2021 PAC meetings

Highlights

- The lowest 50/50 and 90/10 Winter Operable Capacity Margins are projected for week beginning March 6, 2021.

- The lowest 50/50 and 90/10 Spring Operable Capacity Margins are projected for week beginning May 8, 2021.

Summary of the Texas Extreme Cold Weather Event

- During the week beginning on Sunday February 14, the ERCOT Interconnection experienced severe weather and extreme low temperatures that led to supply and demand imbalance
- ERCOT system operators ordered firm customer load shedding beginning in the early morning hours of Monday February 15 to prevent an ERCOT wide blackout
- Resources of every technology type had difficulty with startup and operations; Resource losses were caused by multiple reasons including fuel supply disruption, fuel quality, infrastructure freeze ups, icing, snow cover, and other issues
  - 52,277 MW out of 107,514 MW total installed capacity was forced out or unavailable
- Continued load shedding was required for multiple days in order to maintain a supply and demand balance; The magnitude of the load that had to be disconnected made it difficult to rotate feeders
  - At its peak, ~20,000 MW of load was shed
- ERCOT presented to its Board in an urgent meeting last week, and that presentation was circulated to stakeholders as part of this Participants Committee meeting
- SPP and MISO also experienced emergency conditions during this time frame which required firm customer load shedding but these events were not as extreme as those experienced in ERCOT
  - SPP directed the interruption of service twice: once for approximately 50 minutes on the morning of Feb. 15, and again for a little more than three hours on the morning of Feb. 16.
  - MISO also shed load during the event but exact dates and quantities are not available
- Several investigations are under way including a joint FERC/NERC inquiry and the State of Texas inquiries

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Below Normal (0.9°F) Max: 50°F, Min: 11°F Precipitation: 3.05” – Below Normal Normal: 3.25” Snow: 15.03”	Hartford	Temperature: Below Normal (1.2°F) Max: 48°F, Min: 7°F Precipitation: 3.35” - Above Normal Normal: 2.89” Snow: 20.80”

Peak Load:	18,034 MW	02/01/2021	18:00 (ending)

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

Procedure	Declared	Cancelled	Note
None			

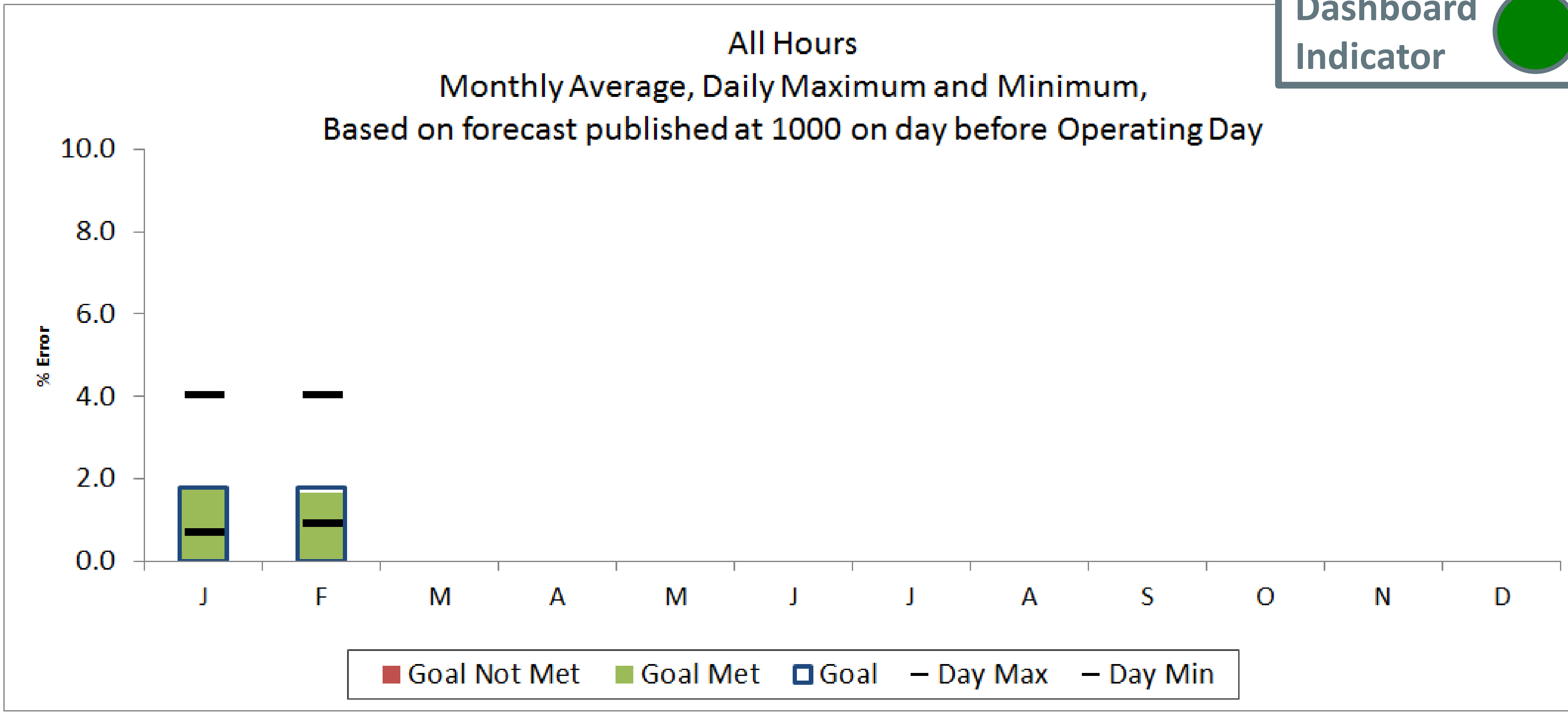
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
None		

2021 System Operations - Load Forecast Accuracy

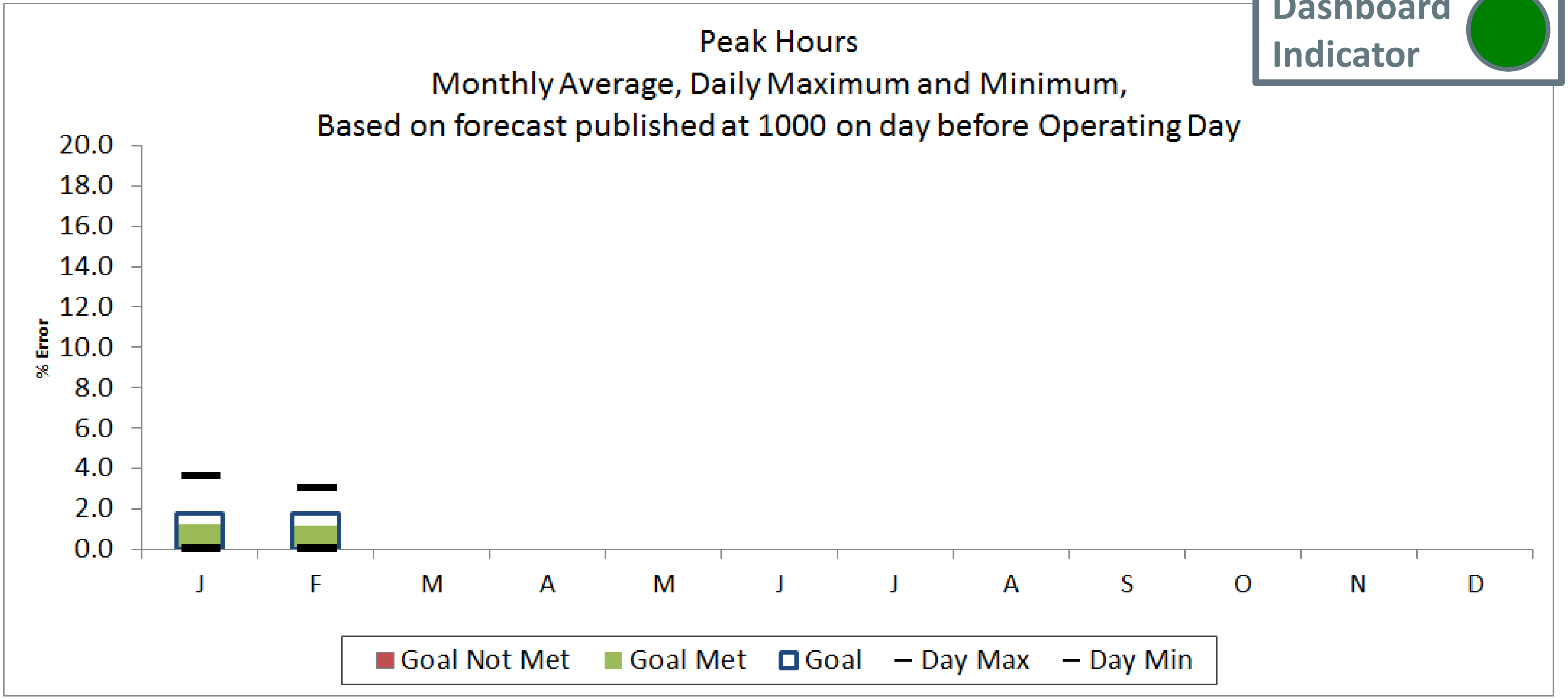
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.04	4.03											4.04
Day Min	0.70	0.92											0.70
MAPE	1.72	1.66											1.69
Goal	1.80	1.80											

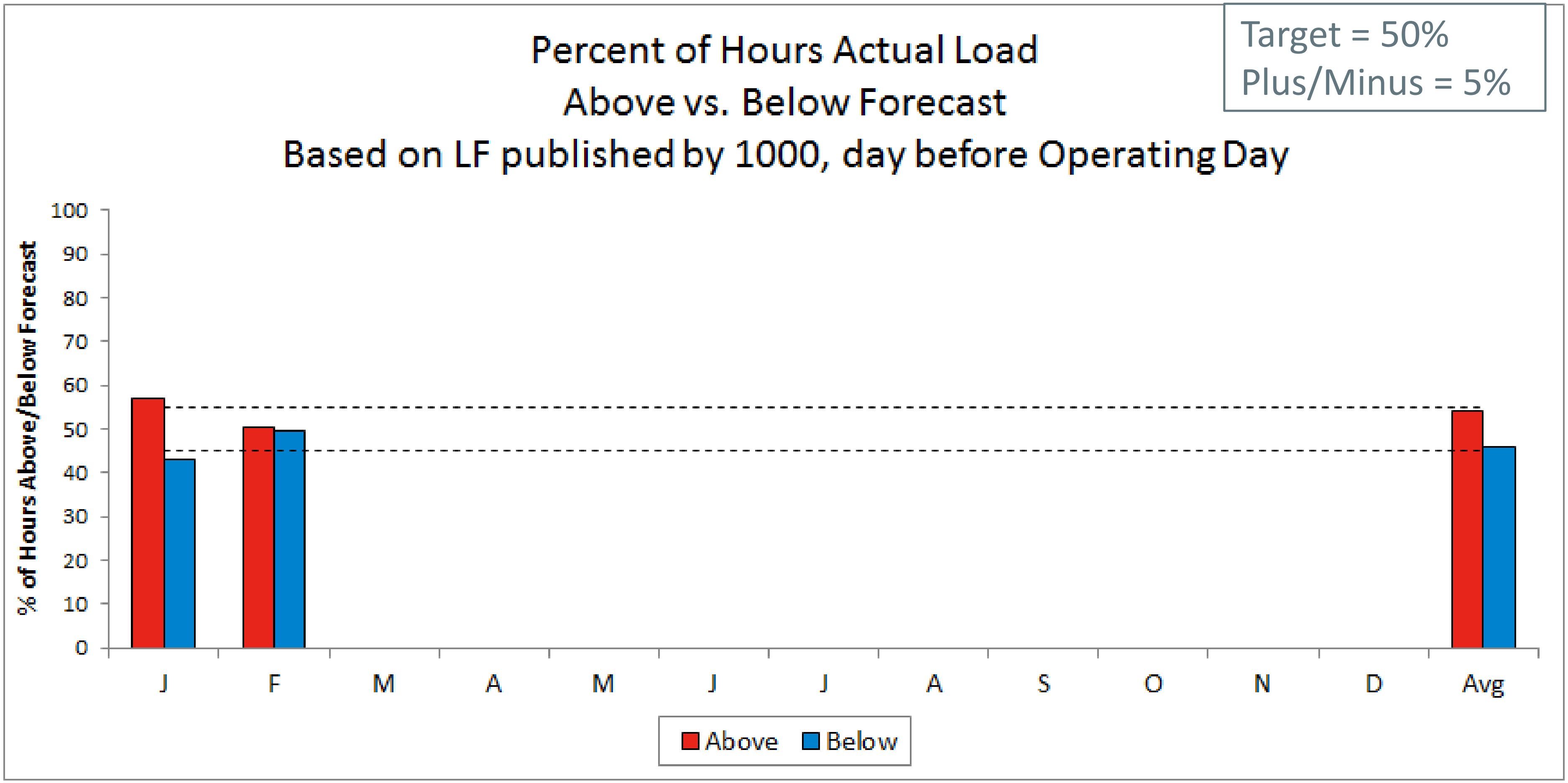
2021 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



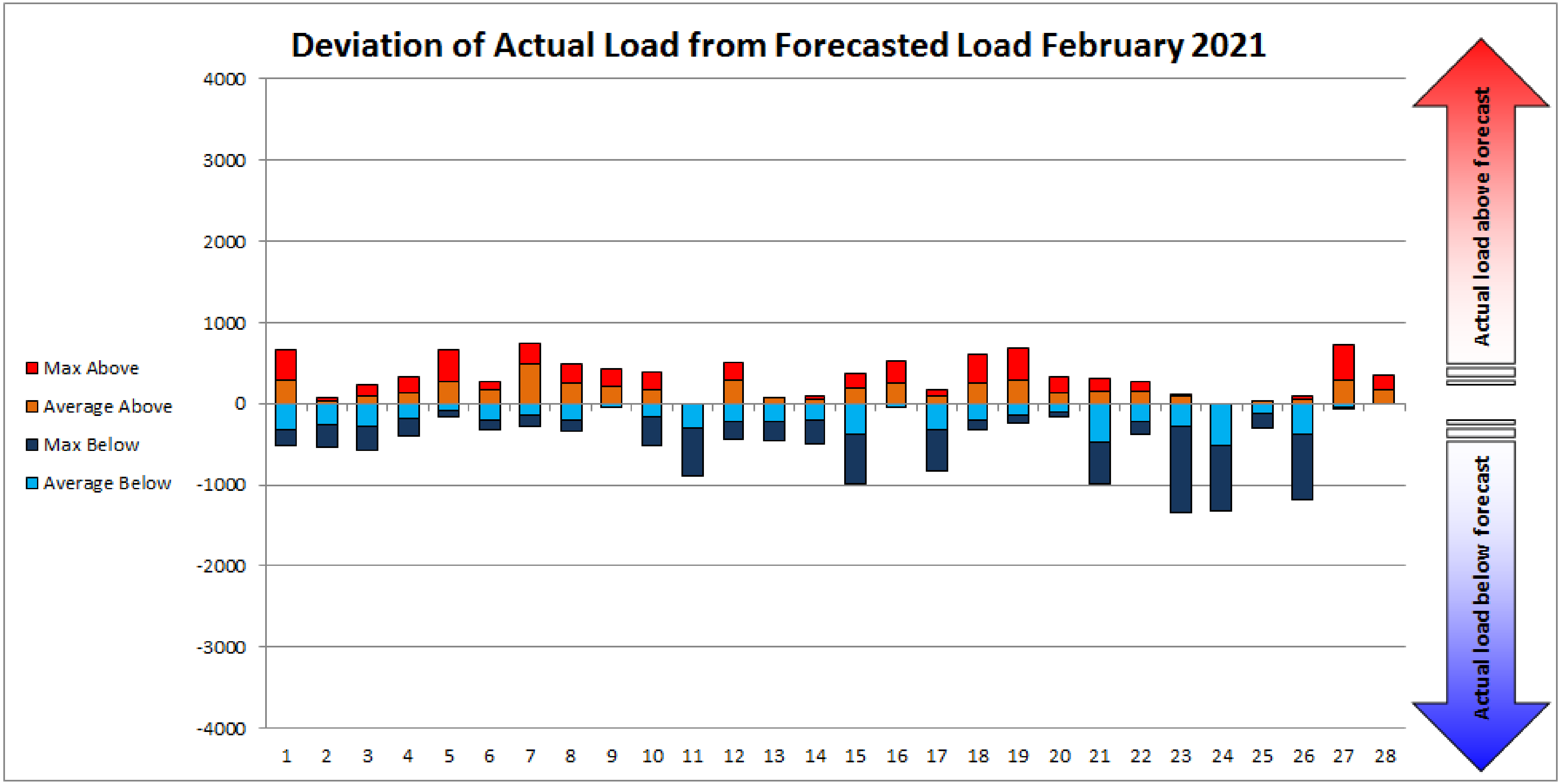
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	3.61	3.03											3.61
Day Min	0.02	0.06											0.02
MAPE	1.26	1.18											1.22
Goal	1.80	1.80											

2021 System Operations - Load Forecast Accuracy cont.

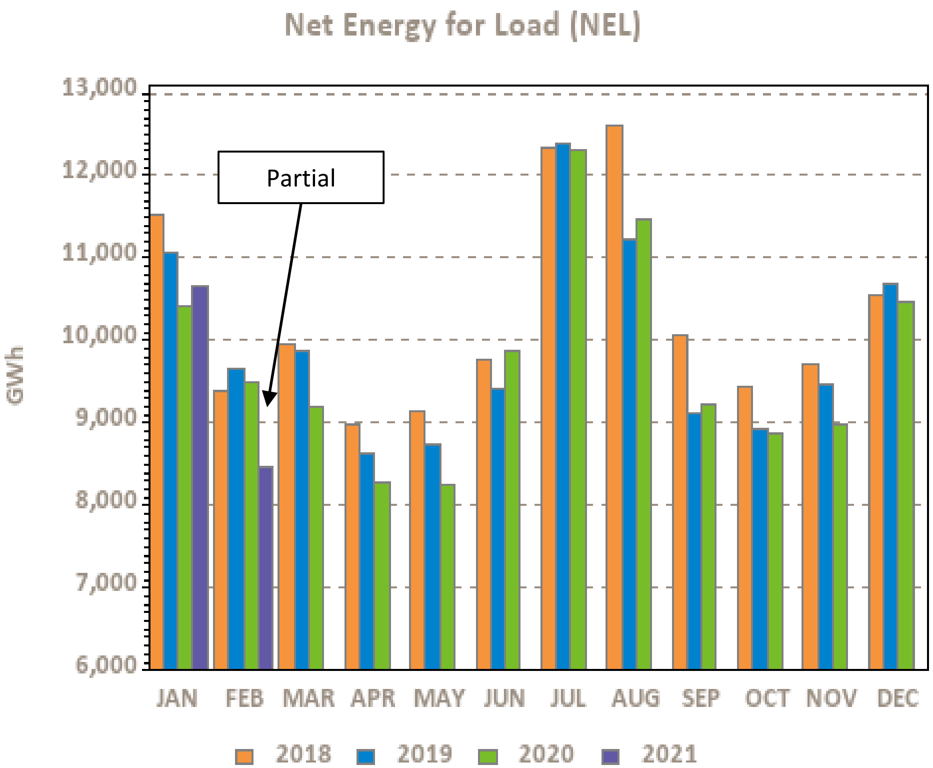


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	57.1	50.4											54
Below %	42.9	49.6											46
Avg Above	209.5	166.7											210
Avg Below	-147.6	-216.4											-216
Avg All	60	-25											20

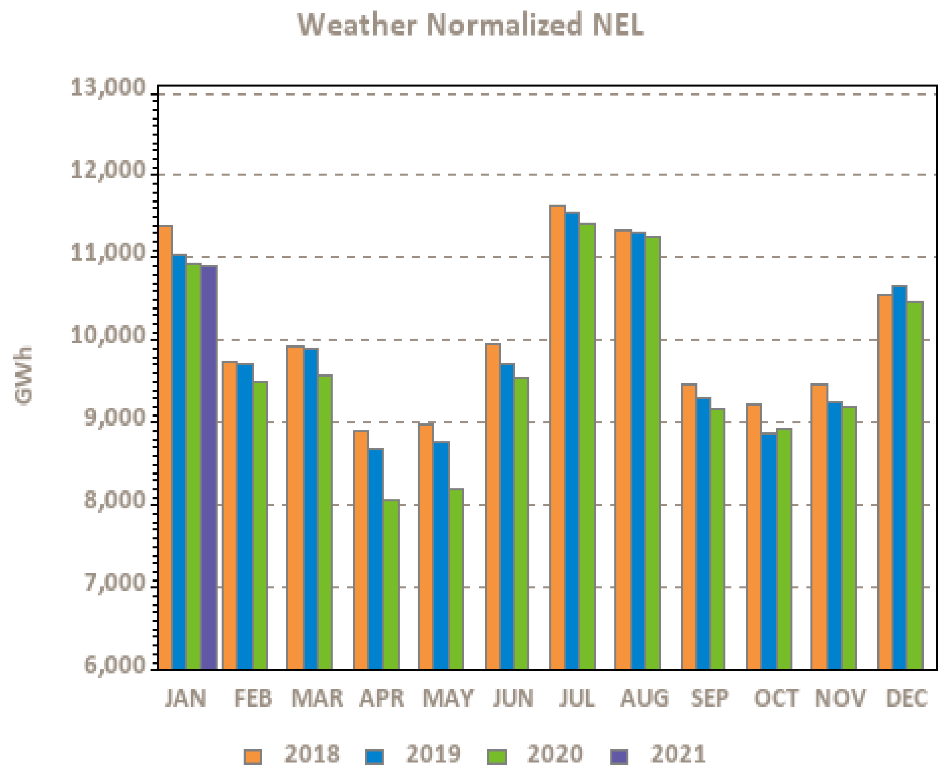
2021 System Operations - Load Forecast Accuracy cont.



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



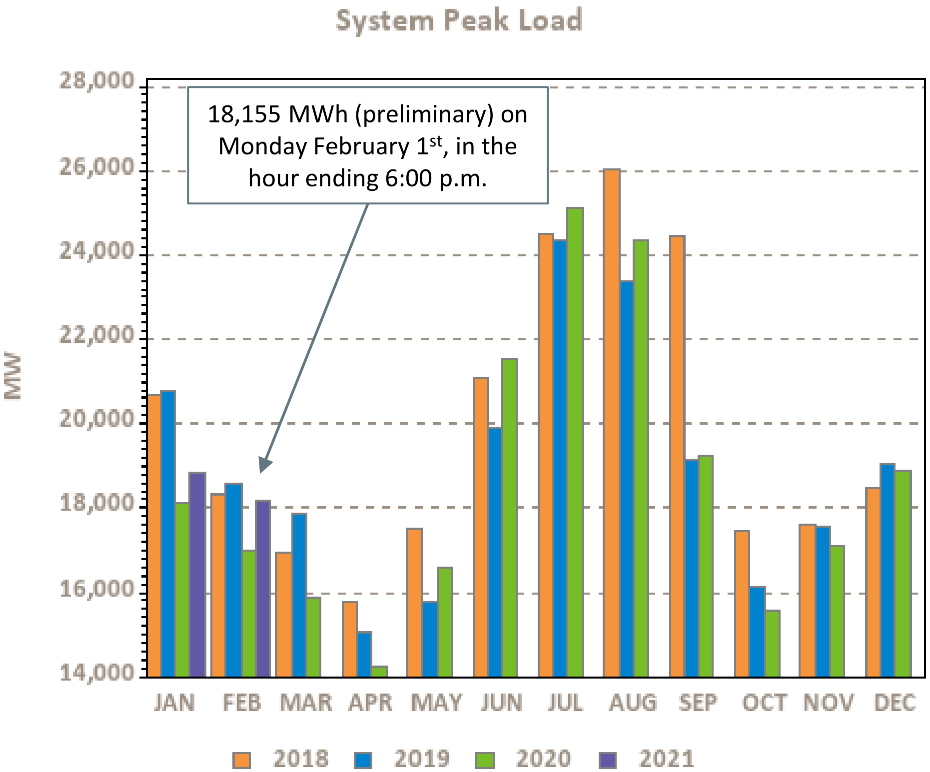
Ann Tot (TWh): 123.5 119.2 116.9 19.1



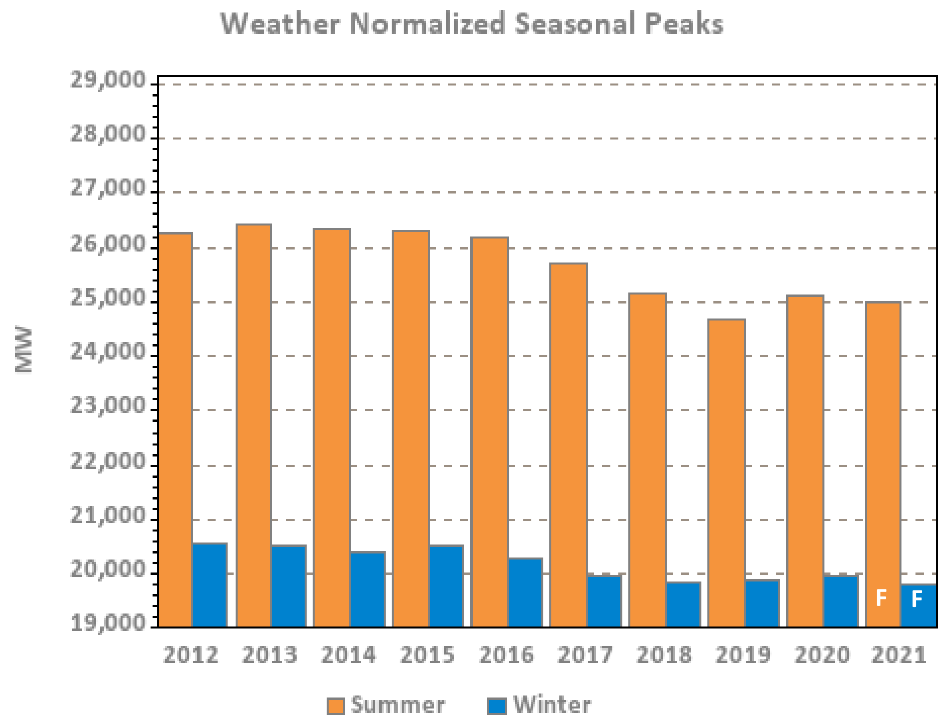
Ann Tot (TWh): 120.6 118.8 116.3 10.9

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

Monthly Peak Loads and Weather Normalized Seasonal Peak History



Revenue quality metered value

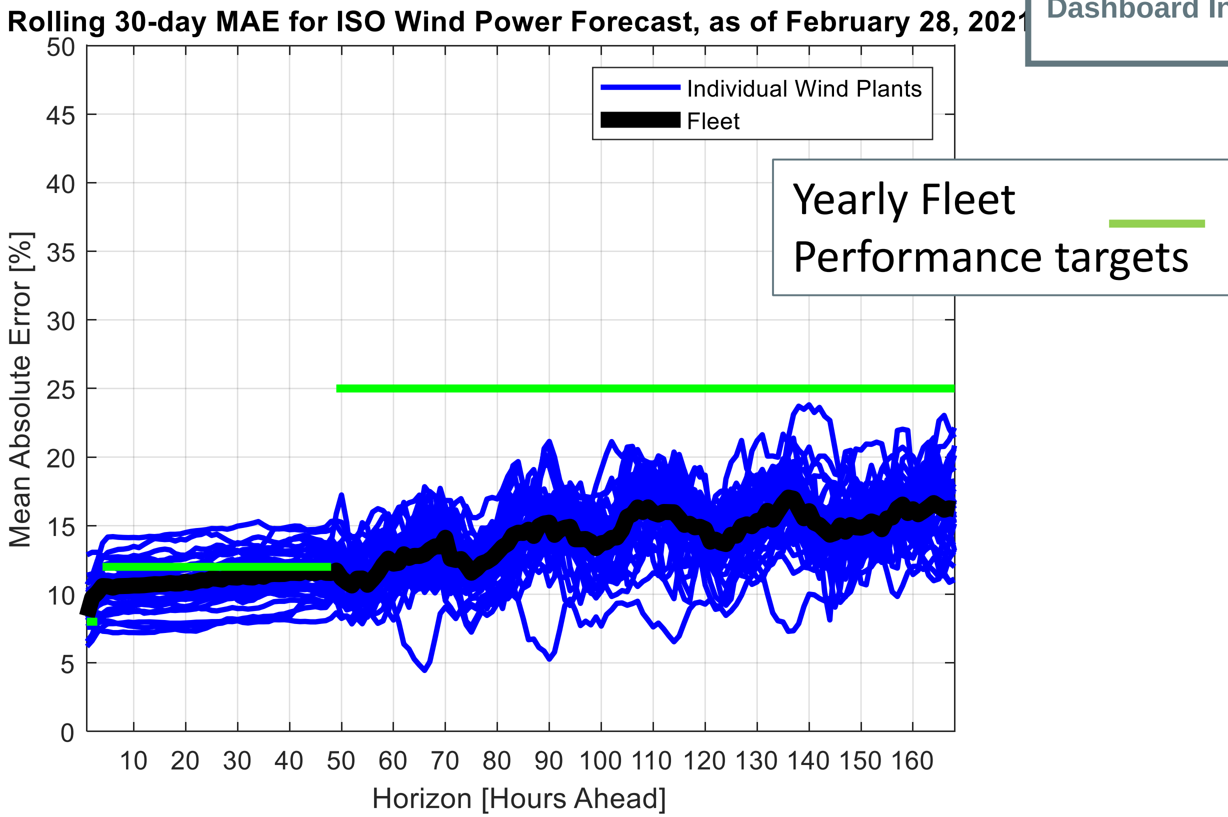


Winter beginning in year displayed

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

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

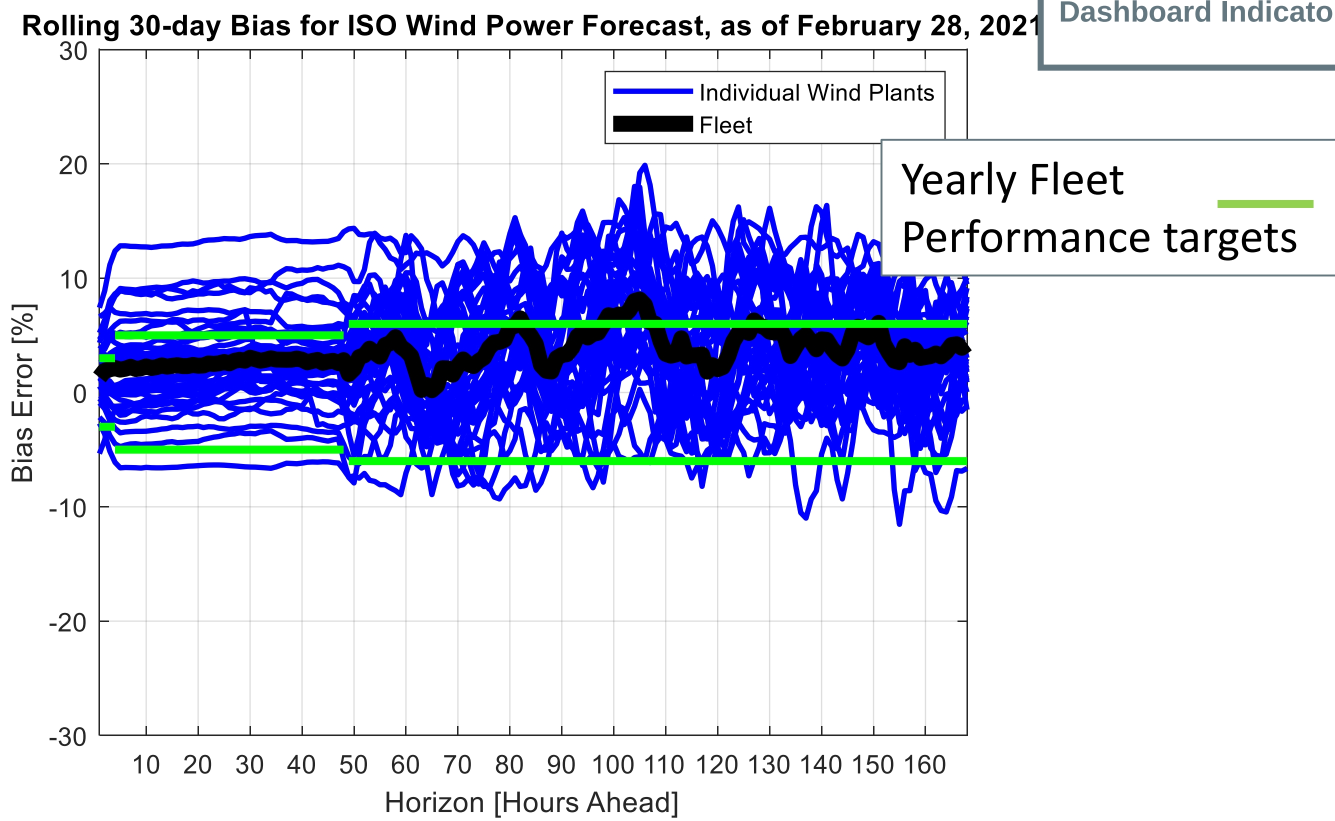
Dashboard Indicator



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

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

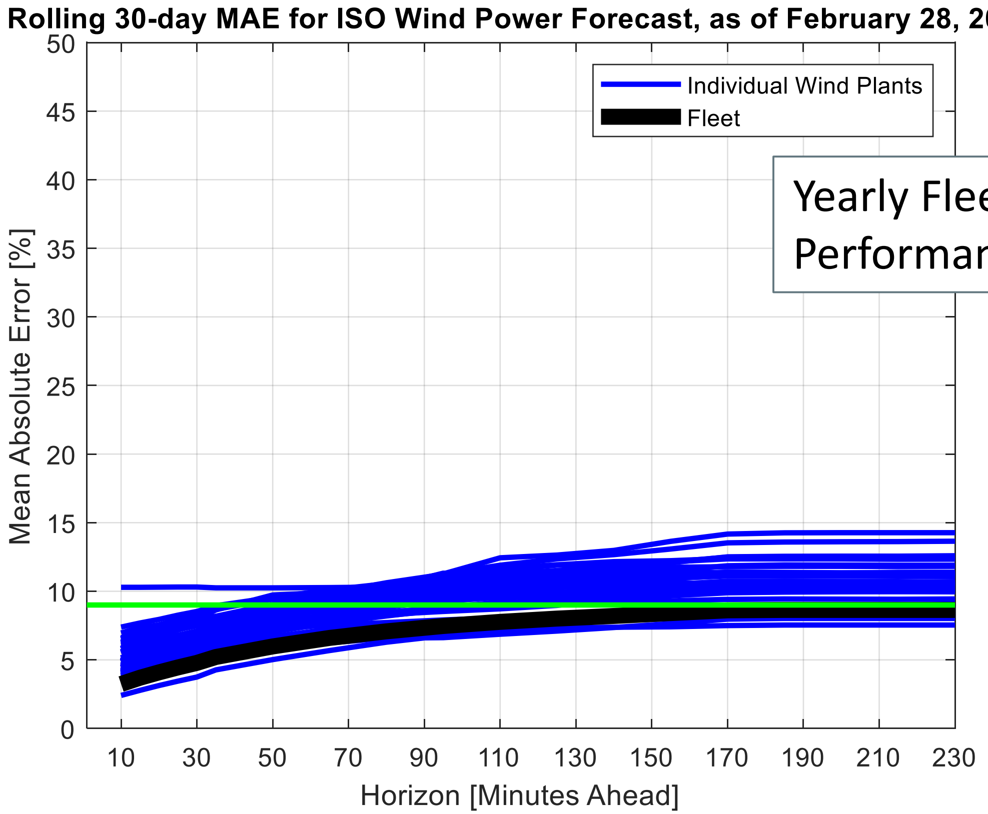
Dashboard Indicator



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

Wind Power Forecast Error Statistics: Short Term Forecast MAE

Dashboard Indicator

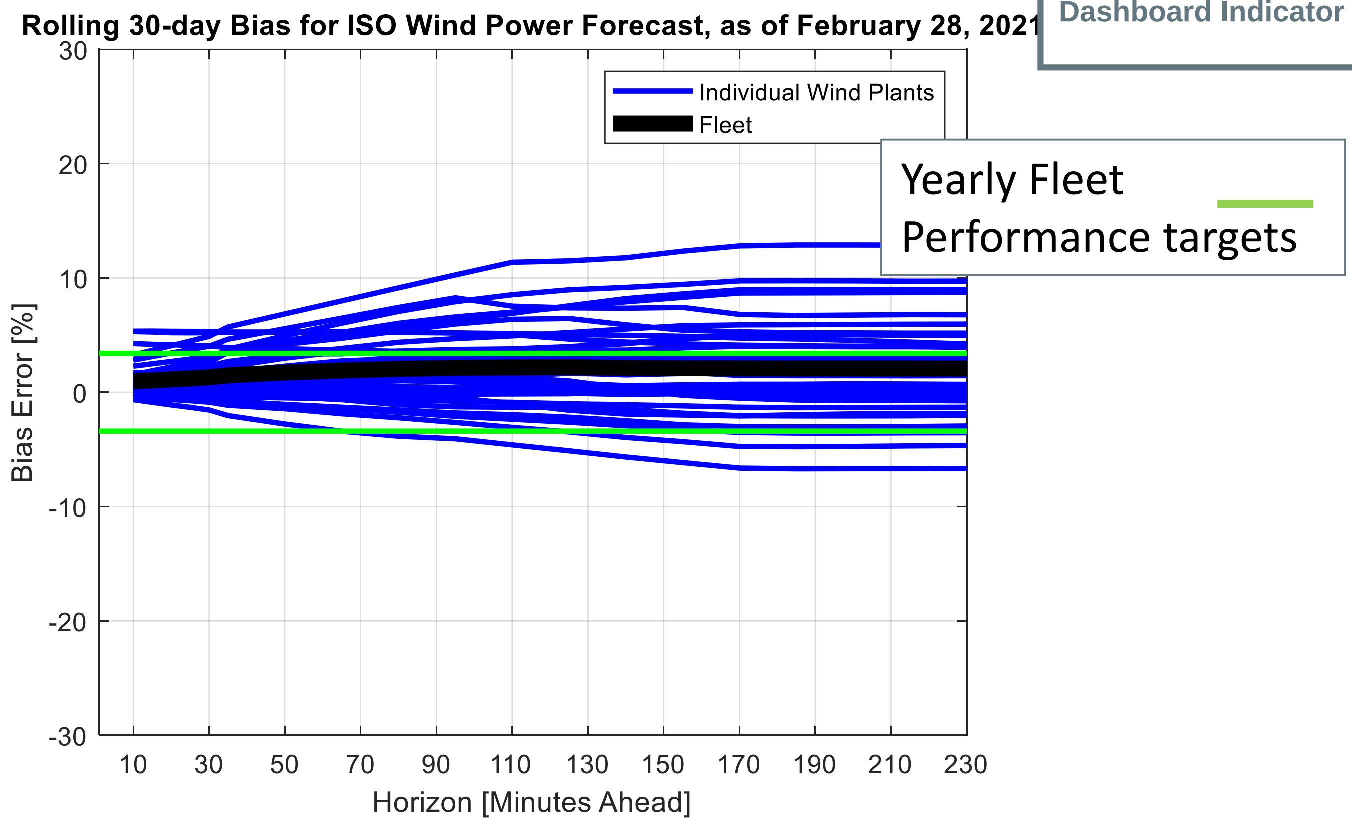


Yearly Fleet Performance targets

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

Wind Power Forecast Error Statistics: Short Term Forecast Bias

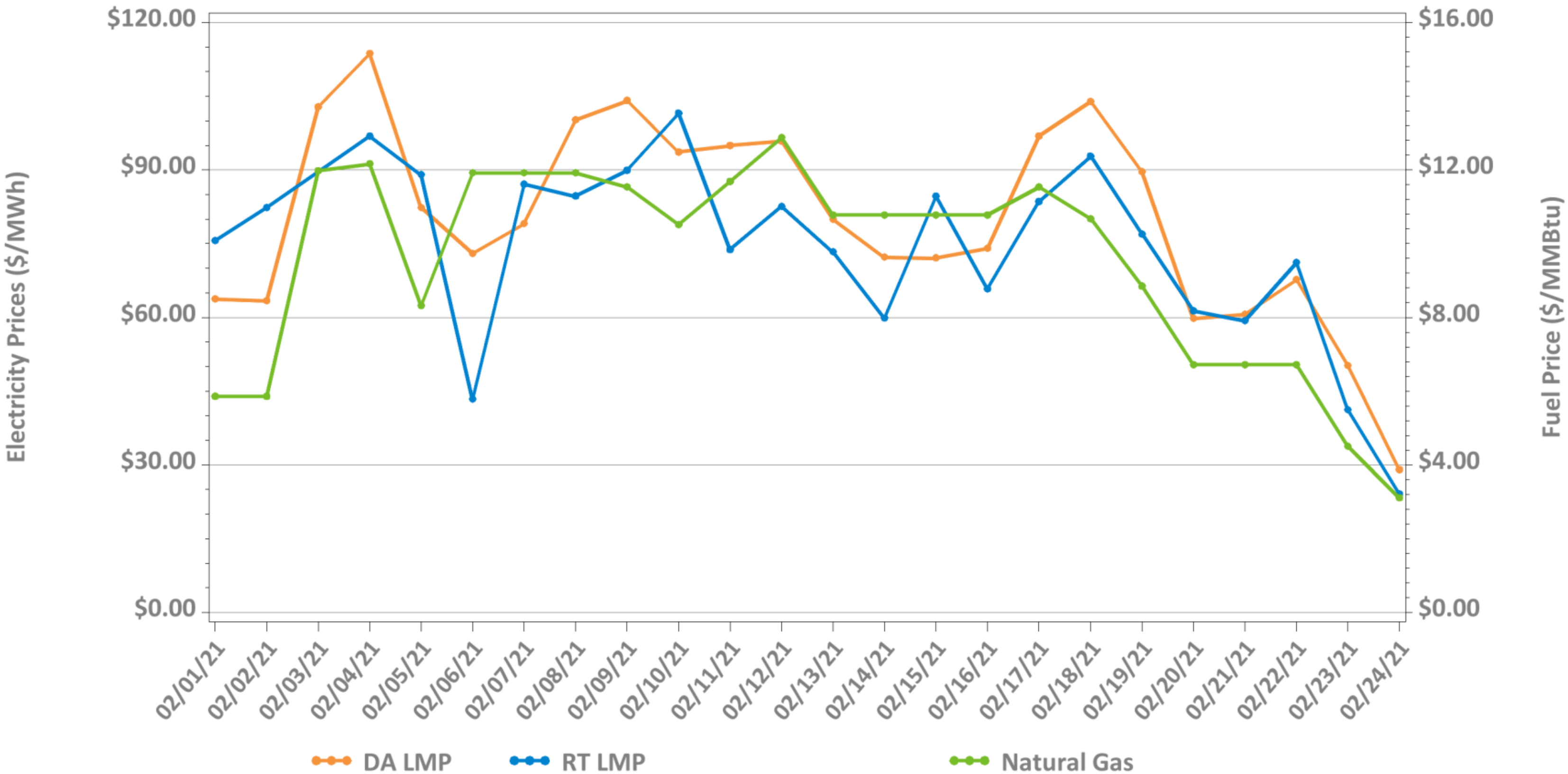
Dashboard Indicator



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

MARKET OPERATIONS

Daily Average DA and RT ISO-NE Hub Prices and Input Fuel Prices: February 1-24, 2021

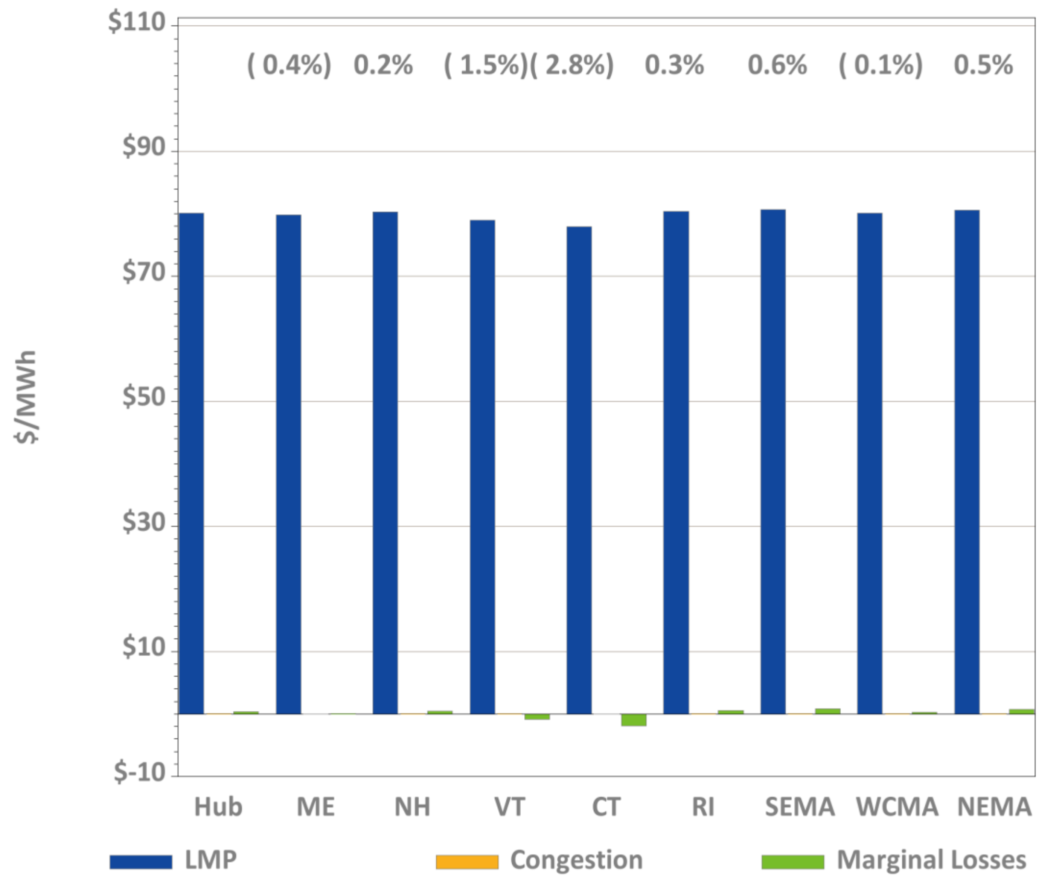


Underlying natural gas data furnished by:

ICE Global markets in clear view

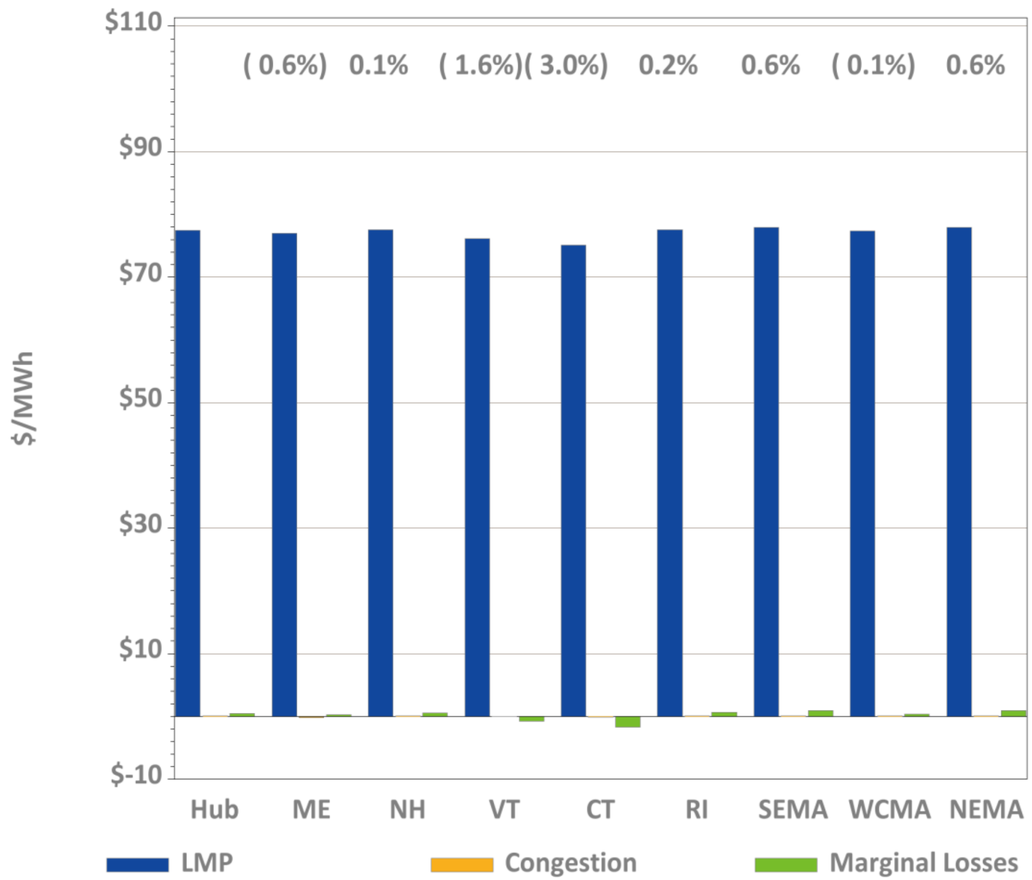
Average price difference over this period (DA-RT): $2.72
Average price difference over this period ABS(DA-RT): $13.13
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 17%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, February 2021



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

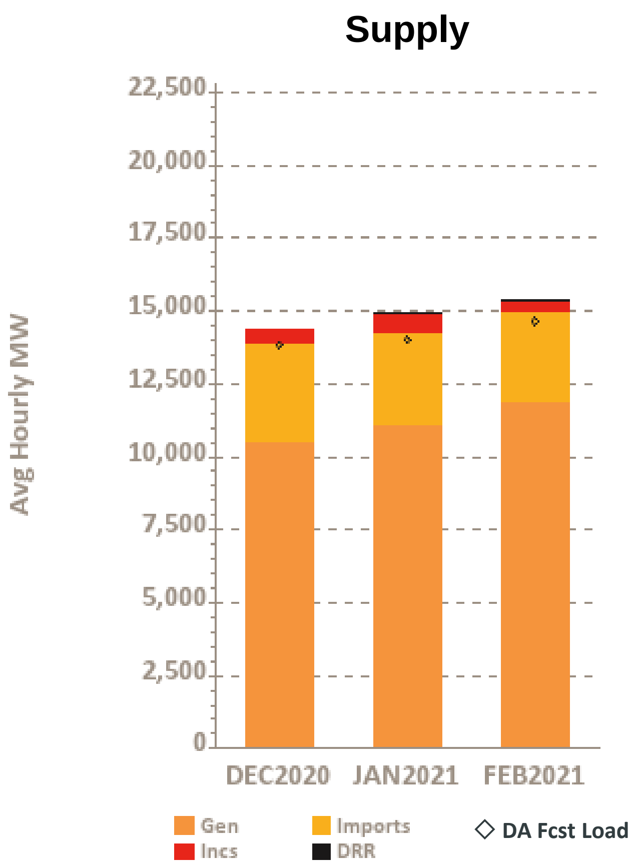
RT LMPs Average by Zone & Hub, February 2021

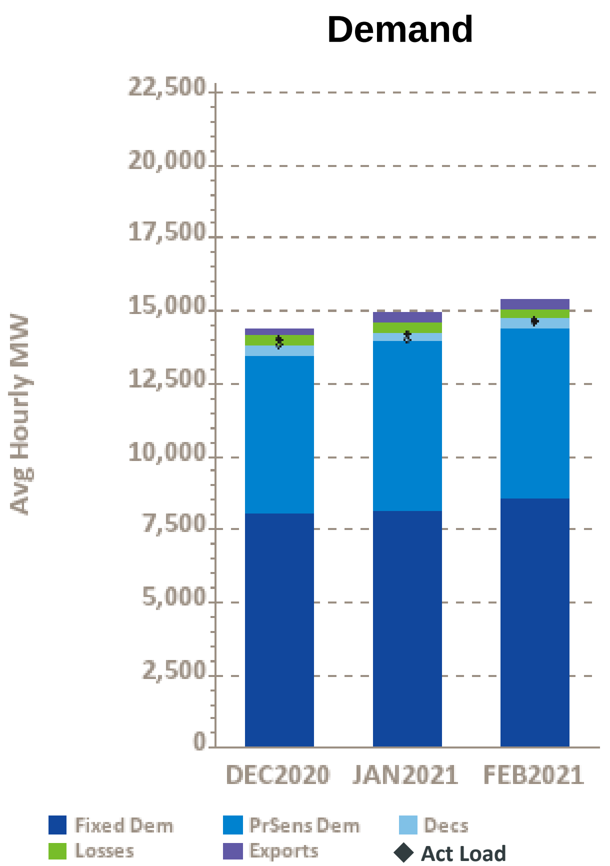


Definitions

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

Components of Cleared DA Supply and Demand – Last Three Months

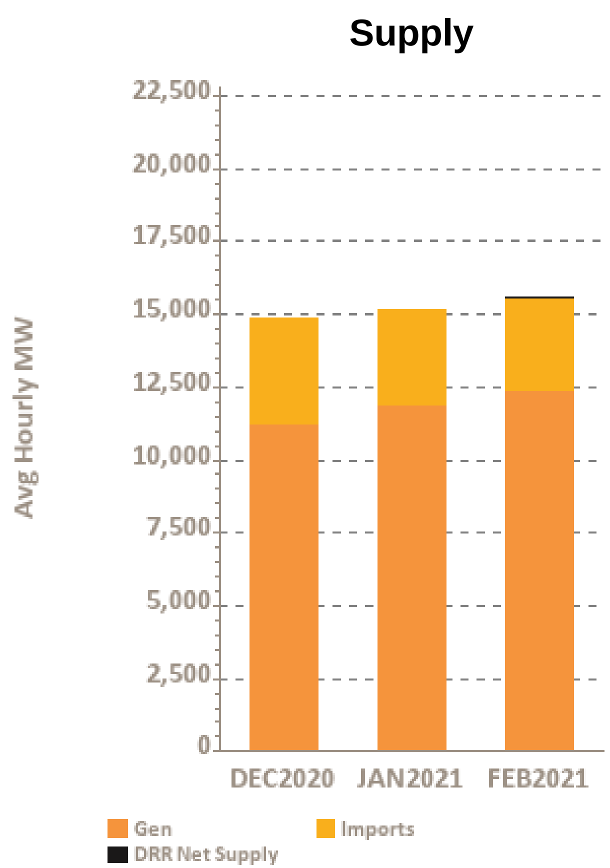


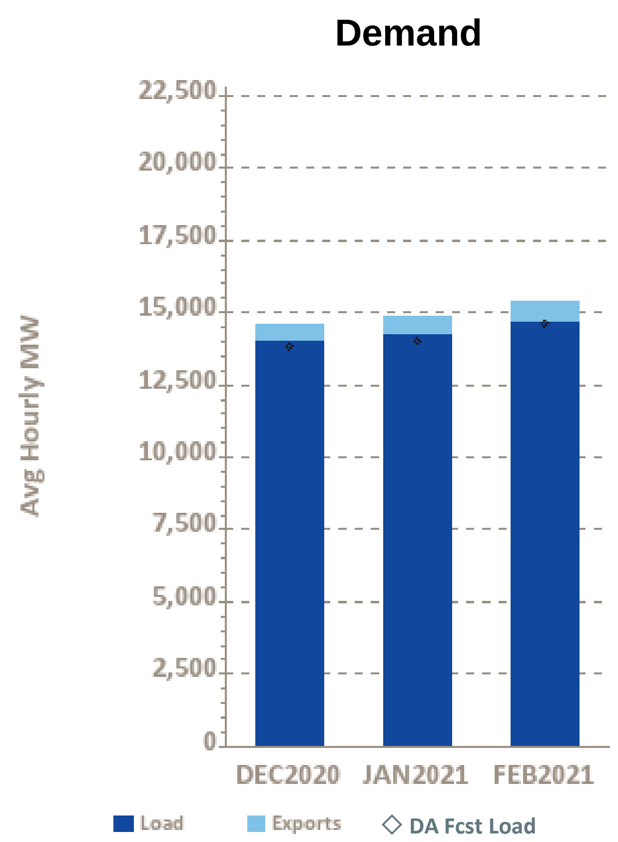


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load
DRR – Demand Response Resource

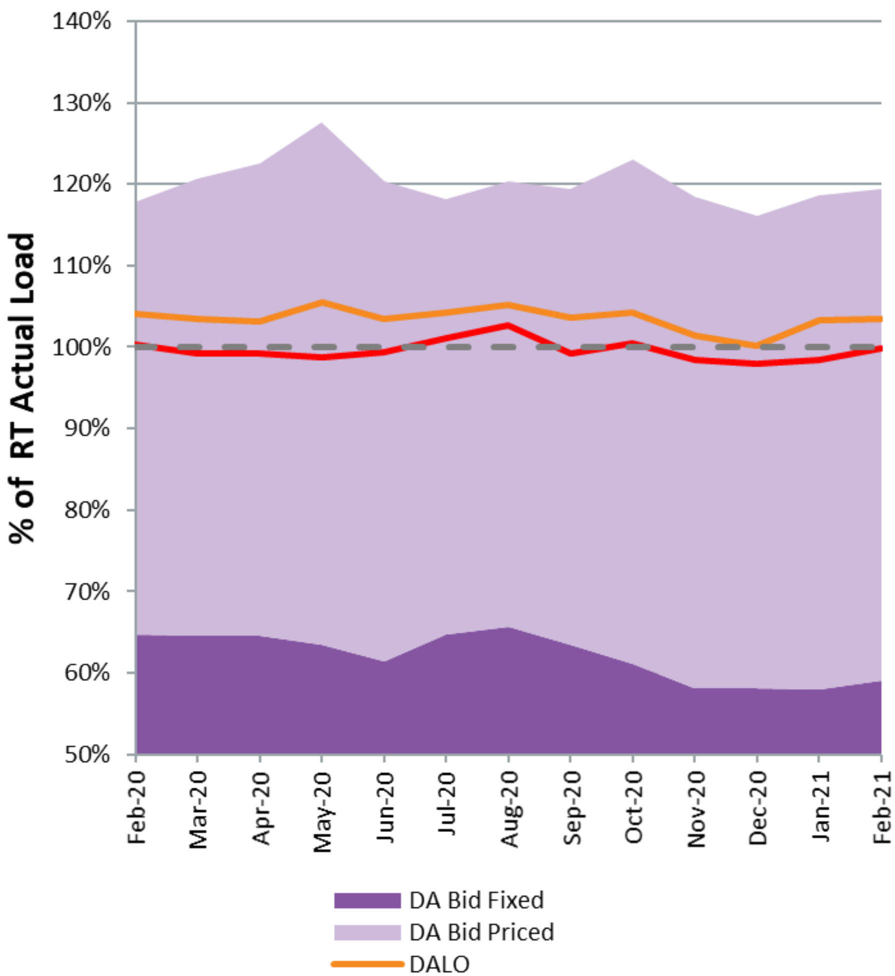
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

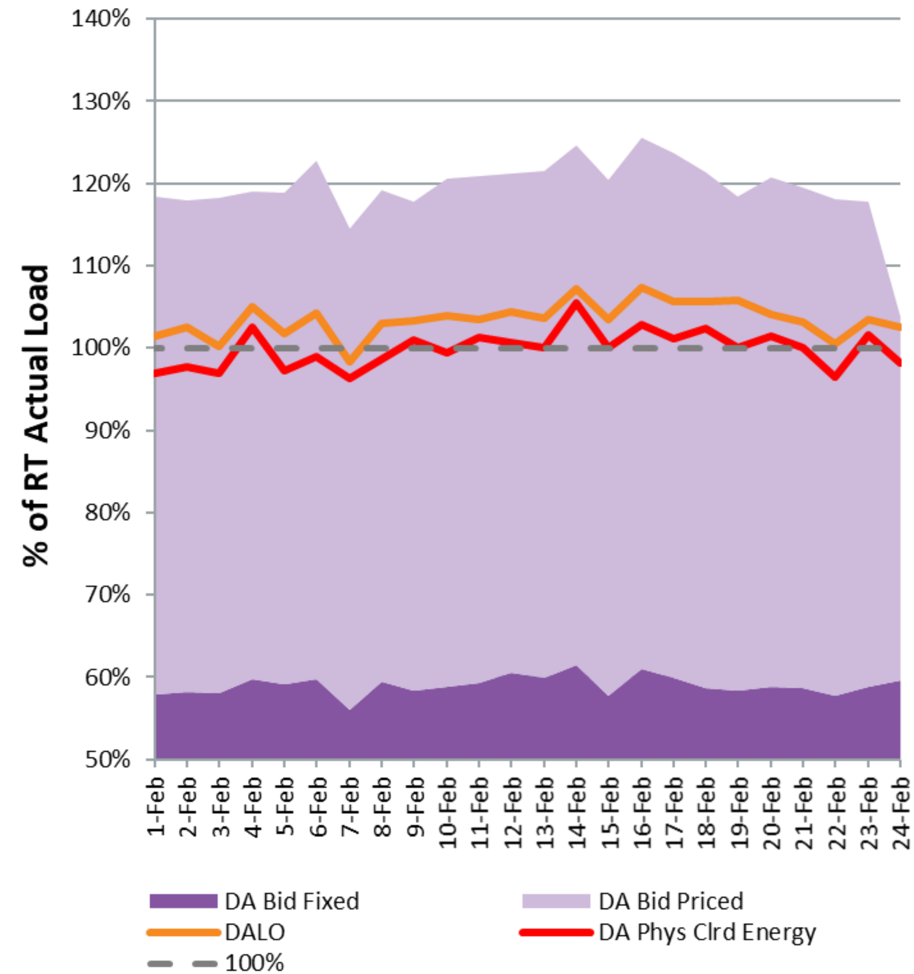
Components of RT Supply and Demand – Last Three Months





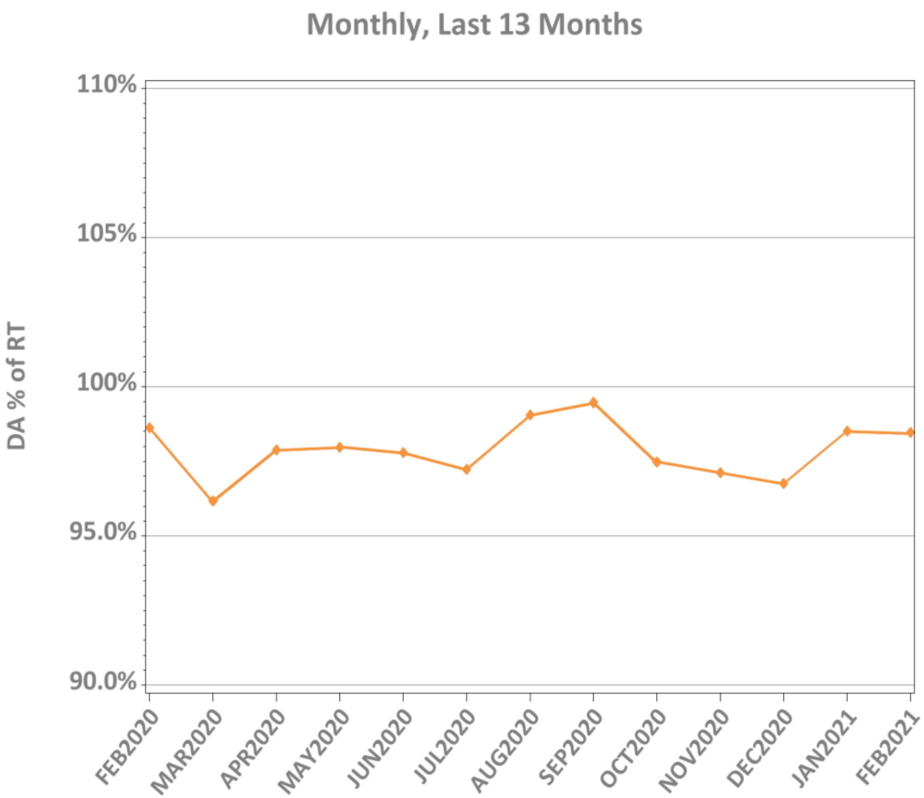
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

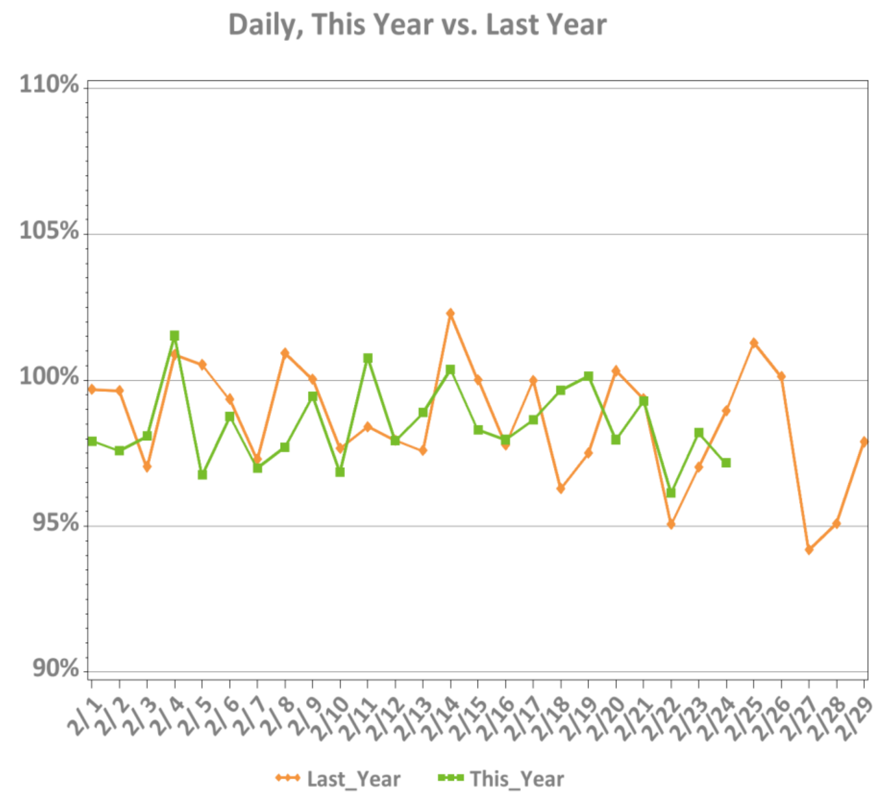




Note: Forecasted peak hour for each day is reflected in the above values. Shown for each day (chart on right) and then averaged for each month (chart on left). 'DA Bid' categories reflect load assets only (Virtual and export bids not reflected.)

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

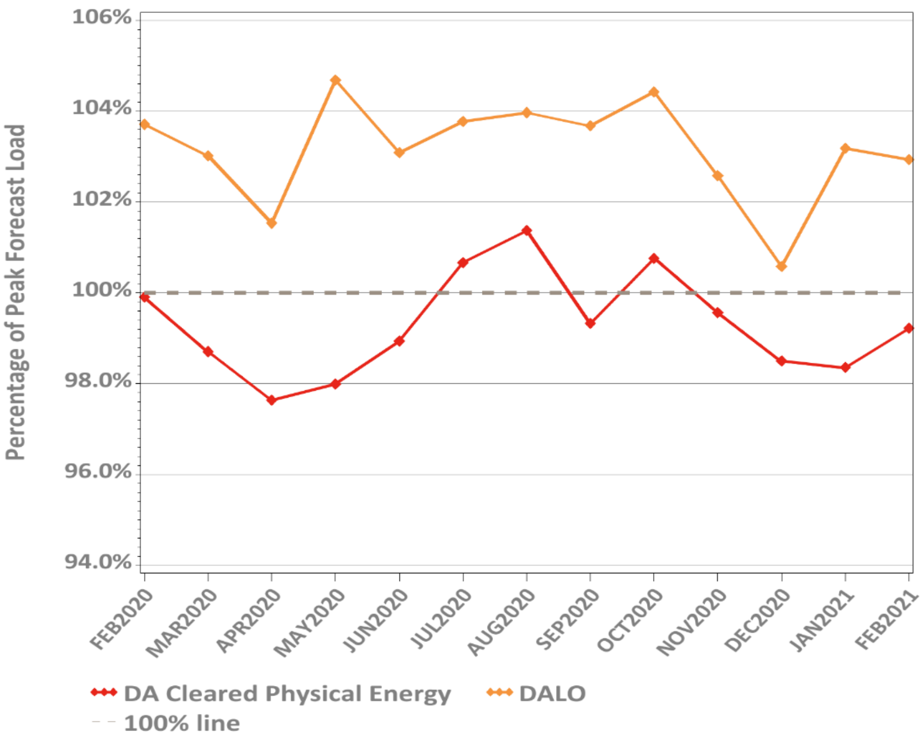




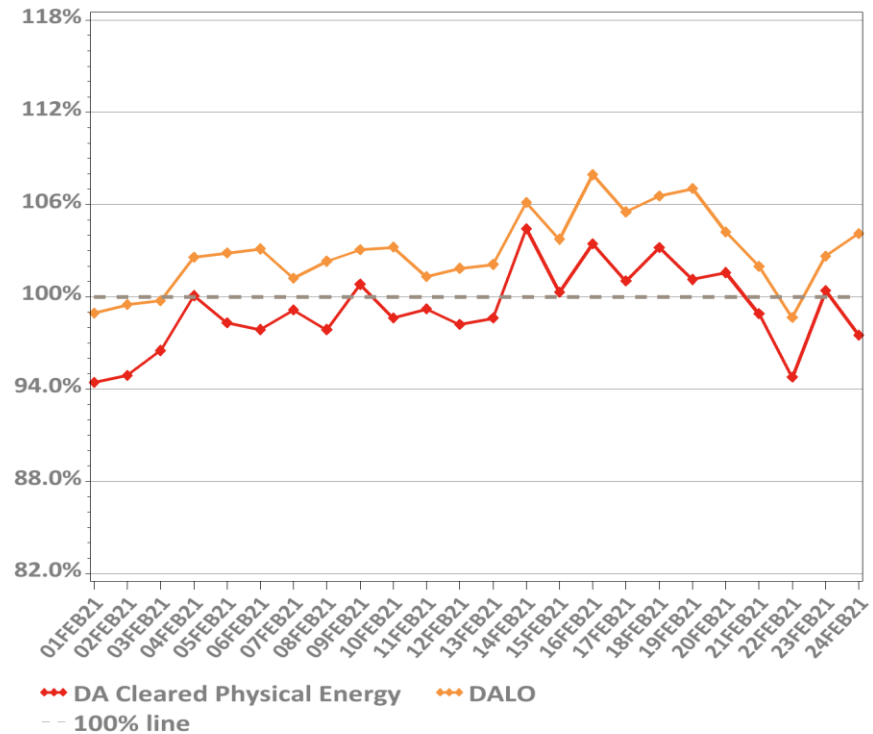
*Hourly average values

DA Volumes as % of Forecast in Peak Hour

Monthly, Last 13 Months

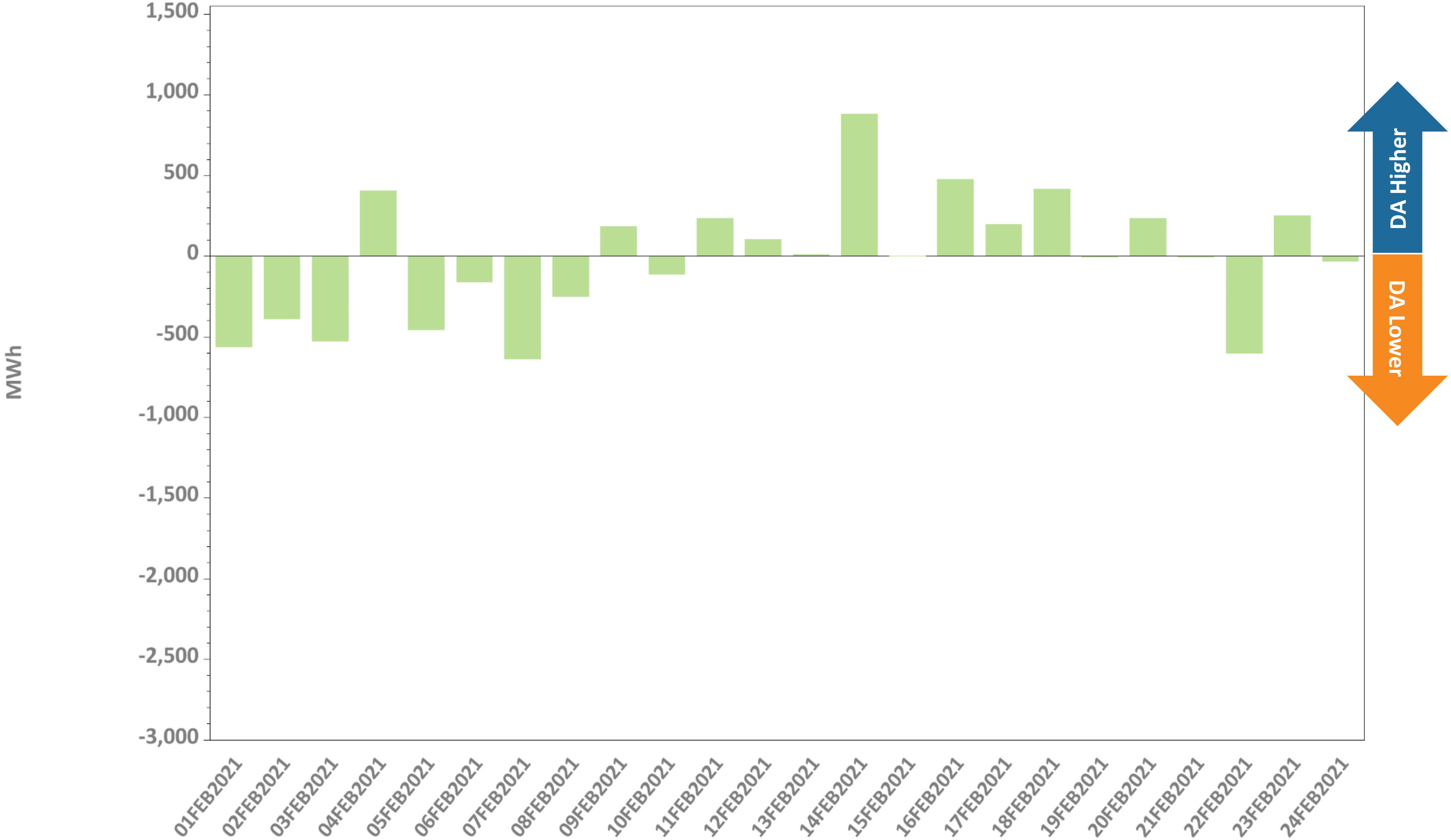


Daily: This Month



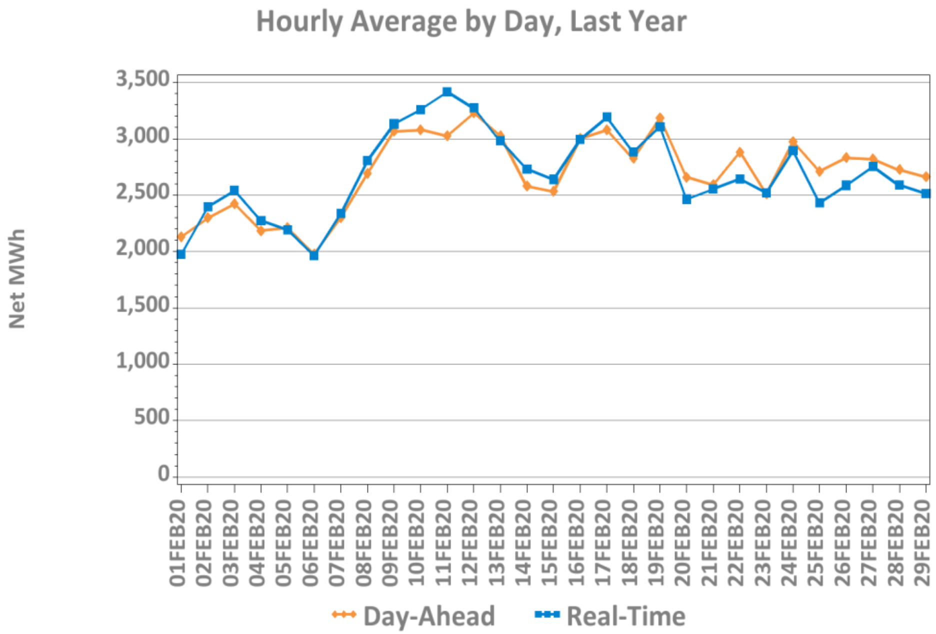
Note: There were no instances of system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) during February.

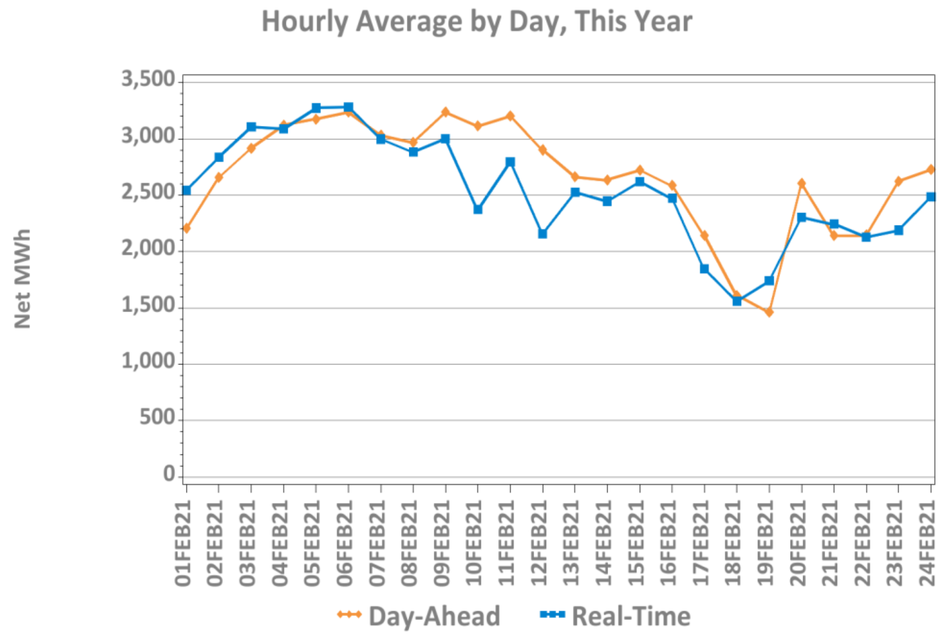
DA Cleared Physical Energy Difference from RT System Load at Peak Hour*



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

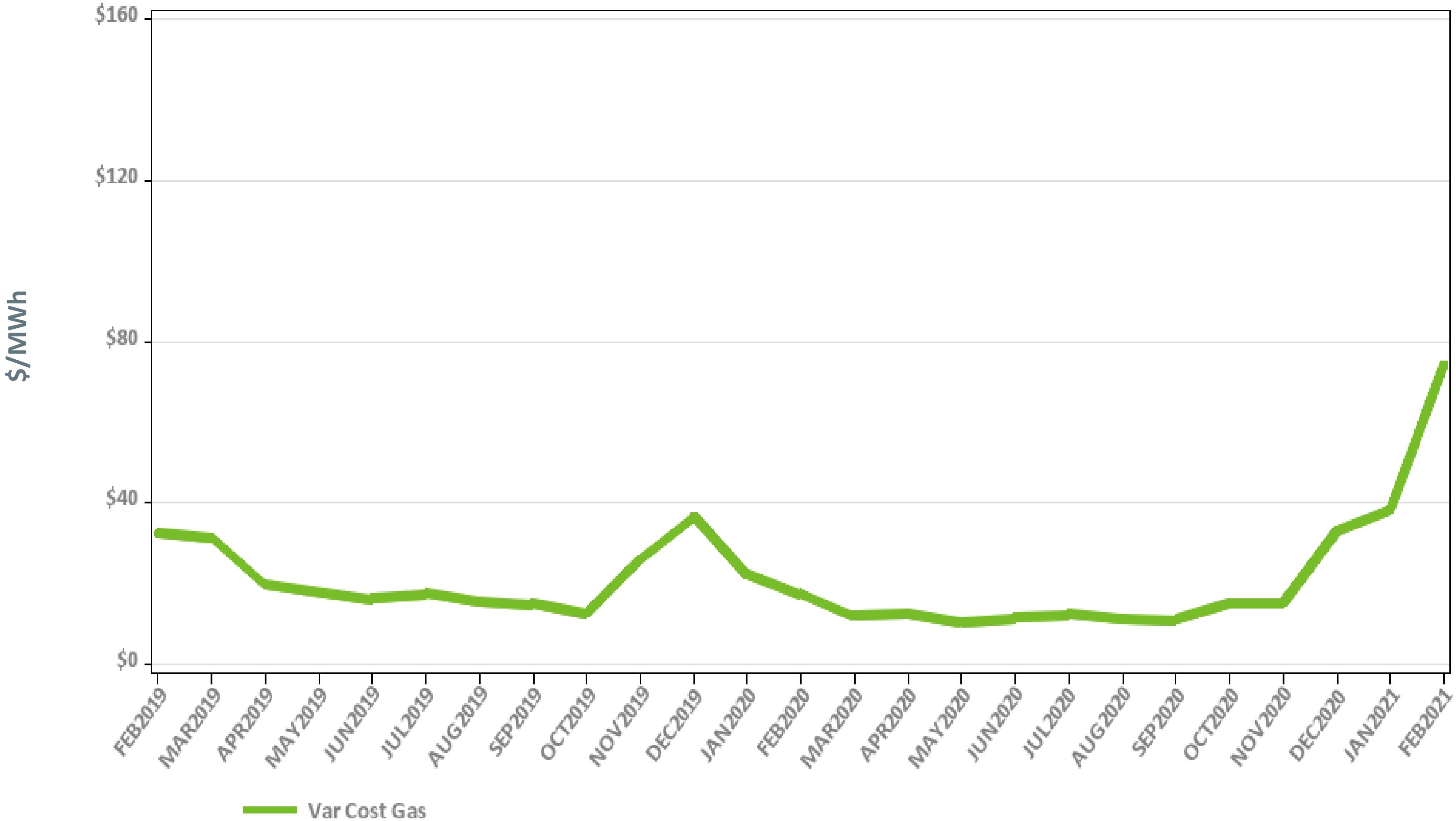
DA vs. RT Net Interchange February 2020 vs. February 2021





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

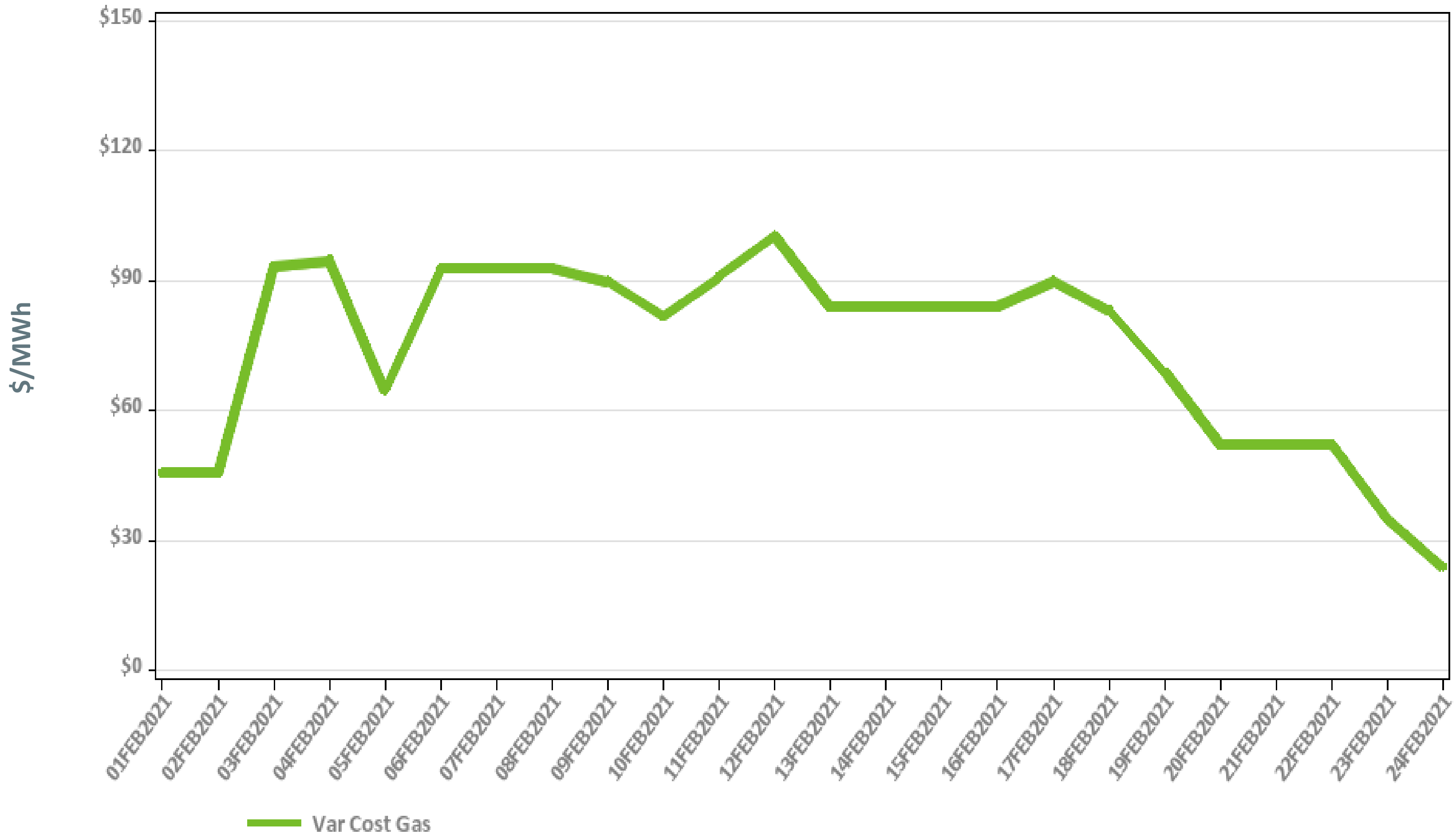
Variable Production Cost of Natural Gas: Monthly



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

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

Variable Production Cost of Natural Gas: Daily

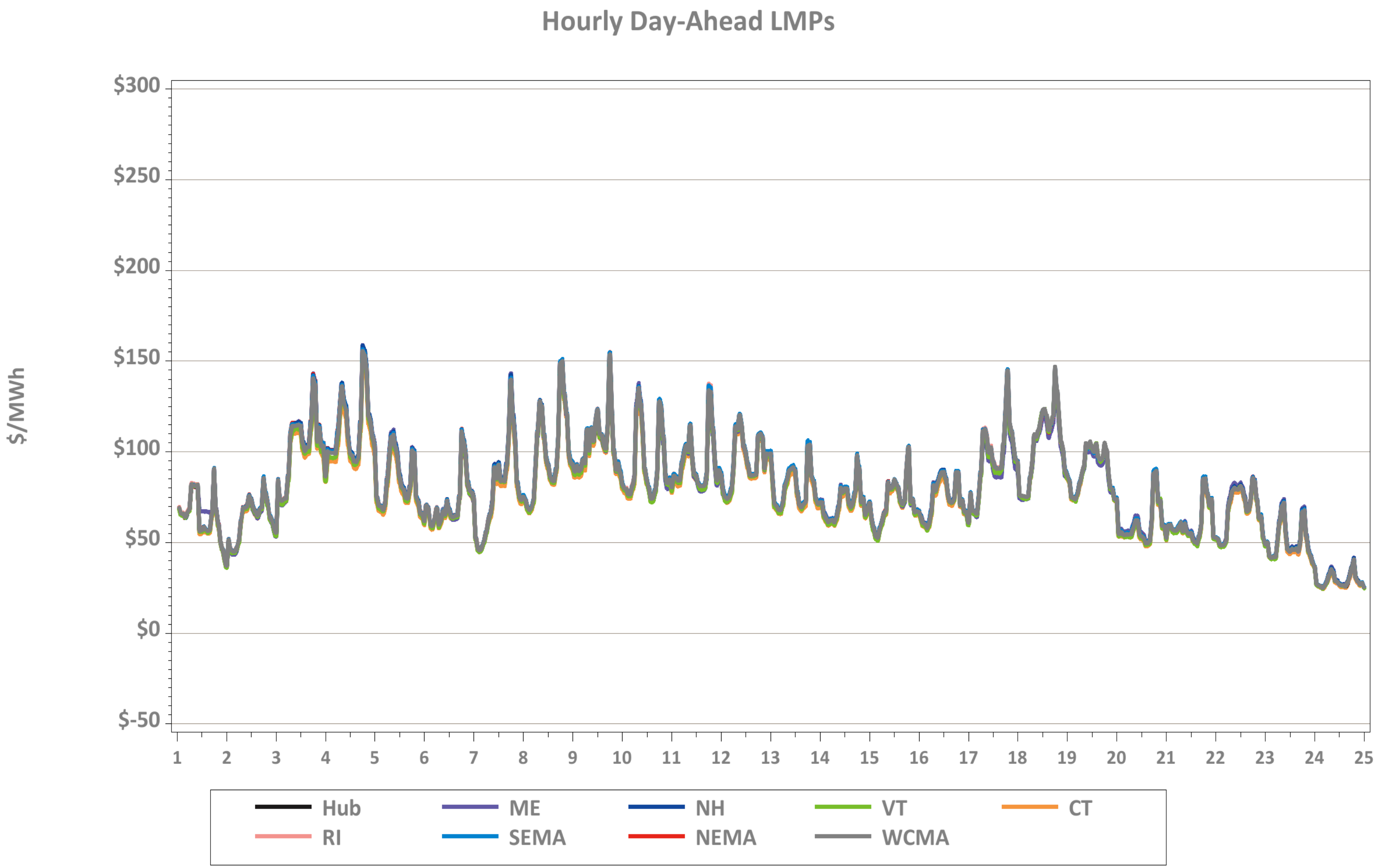


Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

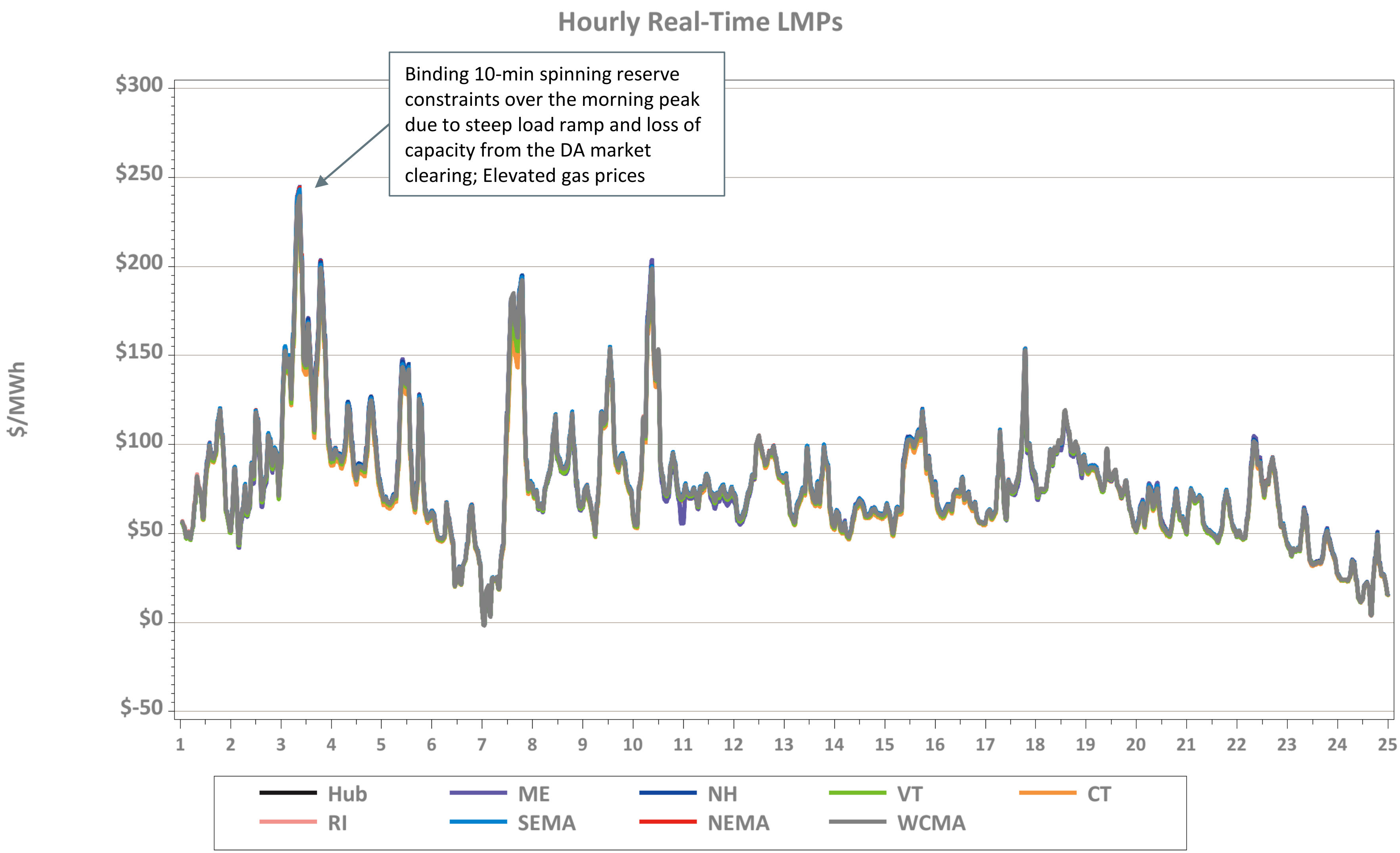
Underlying natural gas data furnished by:

ICE Global markets in clear view

Hourly DA LMPs, February 1-24, 2021

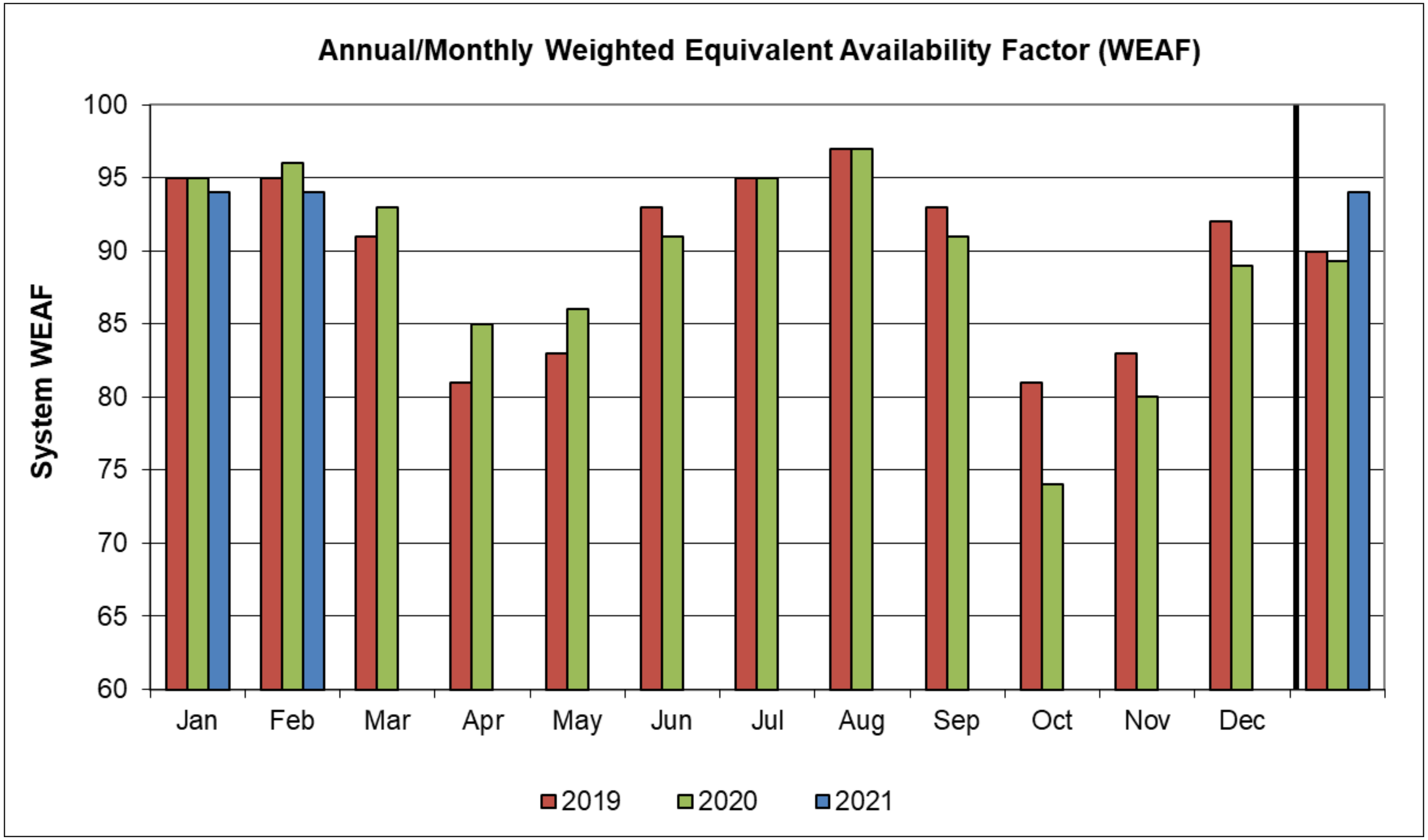


Hourly RT LMPs, February 1-24, 2021



- No Minimum Generation Emergencies were declared during February.

System Unit Availability



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

Data as of 2/24/2021

BACK-UP DETAIL

DEMAND RESPONSE

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

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	79.2	142.0	0.0	221.2
NH	35.0	131.3	0.0	166.2
VT	34.4	133.0	0.0	167.4
CT	107.8	100.8	571.4	780.0
RI	33.9	268.4	0.0	302.3
SEMA	40.1	415.2	0.0	455.3
WCMA	70.7	443.5	26.0	540.2
NEMA	58.3	764.7	0.0	822.9
Total	**459.4**	**2,398.8**	**597.4**	**3,455.6**

*** Active Demand Capacity Resources**

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

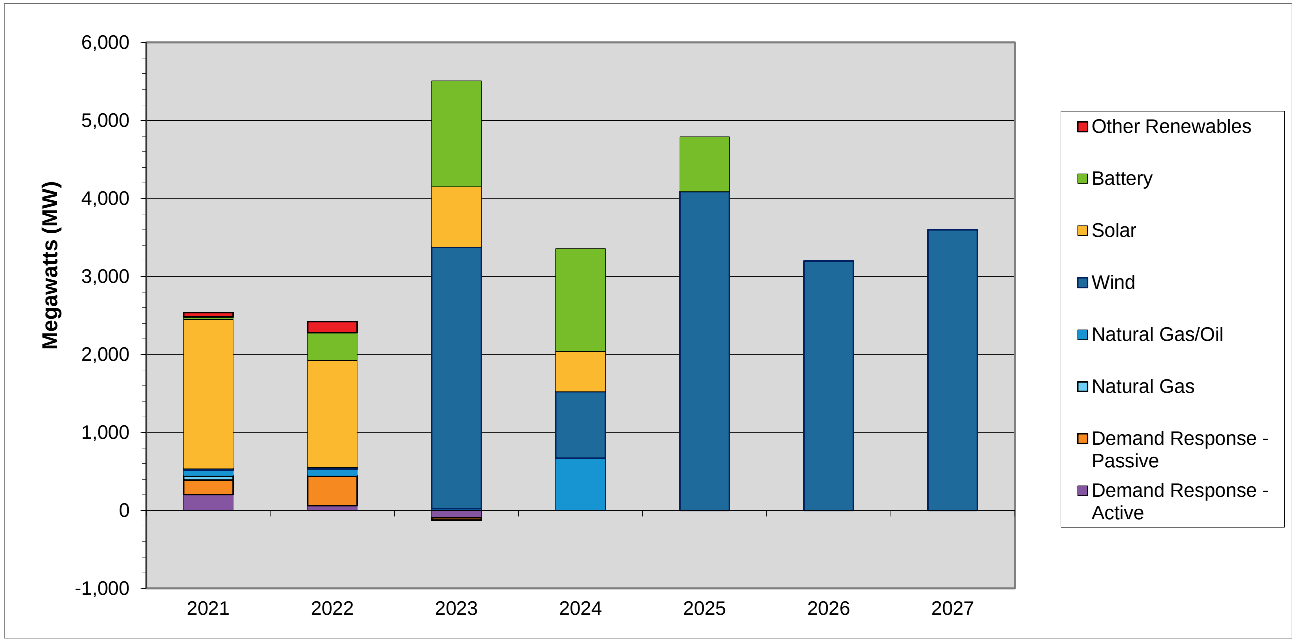
NEW GENERATION

New Generation Update
Based on Queue as of 2/26/21

- Seven new projects totaling 493 MW applied for interconnection study since the last update
  - They consist of seven new PV projects, with in-service dates ranging from 2022 to 2024
- No projects went commercial or were withdrawn, but the capacity of two existing projects was reduced, resulting in a net increase in new generation projects of 373 MW
- In total, 265 generation projects are currently being tracked by the ISO, totaling approximately 24,600 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



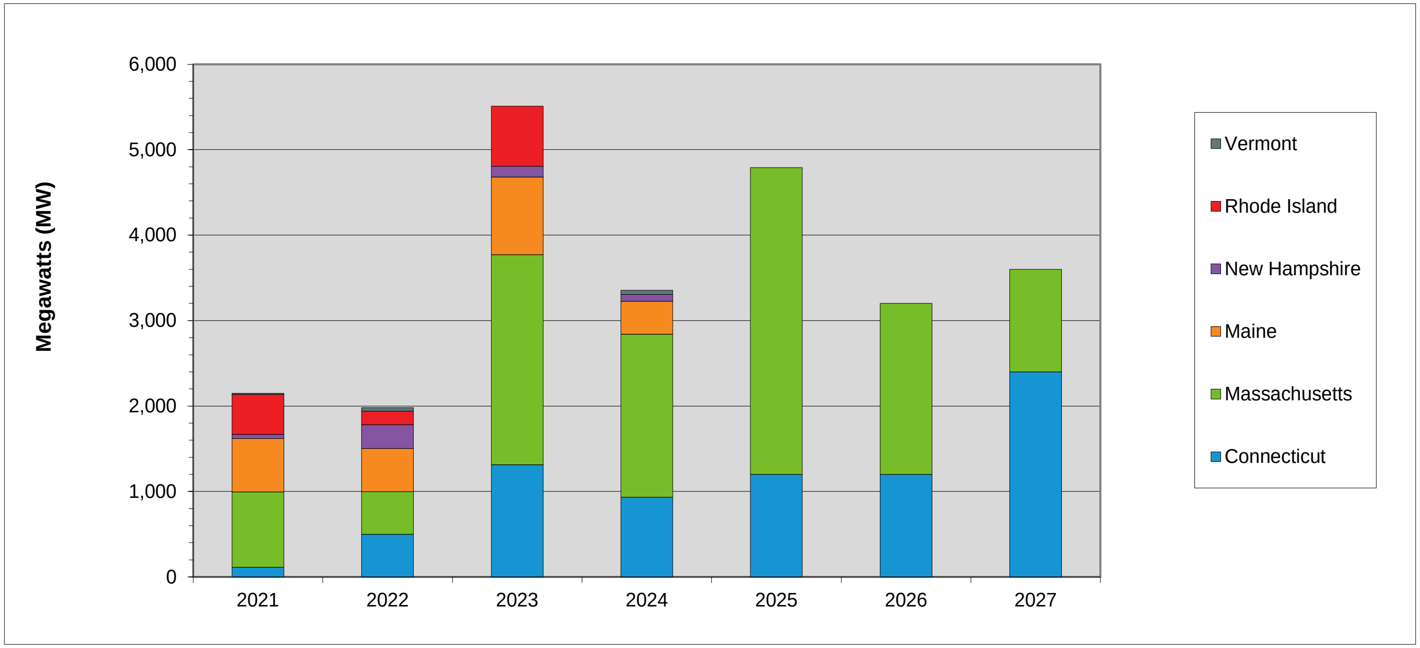
	2021	2022	2023	2024	2025	2026	2027	Total MW	% of Total[1]
Other Renewables	56	142	0	0	0	0	0	198	0.8
Battery	34	358	1,359	1,316	704	0	0	3,771	14.9
Solar[2]	1,912	1,371	772	516	0	0	0	4,571	18.1
Wind	19	20	3,355	852	4,087	3,200	3,600	15,133	59.8
Natural Gas/Oil[3]	76	89	23	672	0	0	0	860	3.4
Natural Gas	53	0	0	0	0	0	0	53	0.2
Demand Response - Passive	184	380	-28	0	0	0	0	536	2.1
Demand Response - Active	204	62	-94	0	0	0	0	172	0.7
Totals	2,538	2,422	5,387	3,356	4,791	3,200	3,600	25,294	100.0

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

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

Actual and Projected Annual Generator Capacity Additions

By State



	2021	2022	2023	2024	2025	2026	2027	Total MW	% of Total[1]
Vermont	15	40	0	50	0	0	0	105	0.4
Rhode Island	466	160	704	0	0	0	0	1,330	5.4
New Hampshire	50	276	126	80	0	0	0	532	2.2
Maine	625	506	907	387	0	0	0	2,425	9.9
Massachusetts	881	500	2,460	1,907	3,591	2,000	1,200	12,539	51.0
Connecticut	113	498	1,312	932	1,200	1,200	2,400	7,655	31.1
Totals	**2,150**	**1,980**	**5,509**	**3,356**	**4,791**	**3,200**	**3,600**	**24,586**	**100.0**

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

New Generation Projection

By Fuel Type

Unit Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	1	8	1	8	0	0
Battery Storage	21	3,771	0	0	21	3,771
Fuel Cell	4	54	1	10	3	44
Hydro	3	99	2	71	1	28
Natural Gas	5	53	0	0	5	53
Natural Gas/Oil	7	860	1	14	6	846
Nuclear	1	37	0	0	1	37
Solar	201	4,571	11	164	190	4,407
Wind	22	15,133	1	15	21	15,118
Total	265	24,586	17	282	248	24,304

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

New Generation Projection

By Operating Type

Operating Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	8	132	3	23	5	109
Intermediate	9	822	1	14	8	808
Peaker	226	8,499	12	230	214	8,269
Wind Turbine	22	15,133	1	15	21	15,118
Total	265	24,586	17	282	248	24,304

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

New Generation Projection

By Operating Type and Fuel Type

Unit Type	Total		Baseload		Intermediate		Peaker		Wind Turbine	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	1	8	1	8	0	0	0	0	0	0
Battery Storage	21	3,771	0	0	0	0	21	3,771	0	0
Fuel Cell	4	54	4	54	0	0	0	0	0	0
Hydro	3	99	2	33	0	0	1	66	0	0
Natural Gas	5	53	0	0	4	47	1	6	0	0
Natural Gas/Oil	7	860	0	0	5	775	2	85	0	0
Nuclear	1	37	1	37	0	0	0	0	0	0
Solar	201	4,571	0	0	0	0	201	4,571	0	0
Wind	22	15,133	0	0	0	0	0	0	22	15,133
Total	265	24,586	8	132	9	822	226	8,499	22	15,133

- 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**

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

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

Capacity Supply Obligation FCA 12

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	624.445	659.137	34.692	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**		

* 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**				

* 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**						

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

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

Capacity Supply Obligation FCA 15

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	677.673						
	Passive Demand	3,212.865						
Demand Total		**3,890.538**						
Generator	*Non-Intermittent*	28,154.203						
	Intermittent	1,089.265						
Generator Total		**29,243.468**						
Import Total		**1,487.059**						
Grand Total*		**34,621.065**						
Net ICR (NICR)		**33,270**						

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

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

Active/Passive Demand Response

CSO Totals by Commitment Period

Commitment Period	Active/Passive	Existing	New	Grand Total
2019-20	Active	357.221	20.304	377.525
	Passive	2,018.20	350.43	2,368.63
	Grand Total	2,375.422	370.734	2,746.156
2020-21	Active	334.634	85.294	419.928
	Passive	2,236.73	554.292	2,791.02
	Grand Total	2,571.361	639.586	3,210.947
2021-22	Active	480.941	143.504	624.445
	Passive	2,604.79	370.568	2,975.36
	Grand Total	3,085.734	514.072	3,599.806
2022-23	Active	598.376	87.178	685.554
	Passive	2,788.33	566.363	3,354.69
	Grand Total	3,386.703	653.541	4,040.244
2023-24	Active	560.55	31.493	592.043
	Passive	3,035.51	291.565	3,327.07
	Grand Total	3,596.056	323.058	3,919.114
2024-25	Active	674.153	3.520	677.673
	Passive	3,046.064	166.801	3,212.865
	Grand Total	**3,720.217**	**170.321**	**3,890.538**

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

What are Daily NCPC Payments?

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

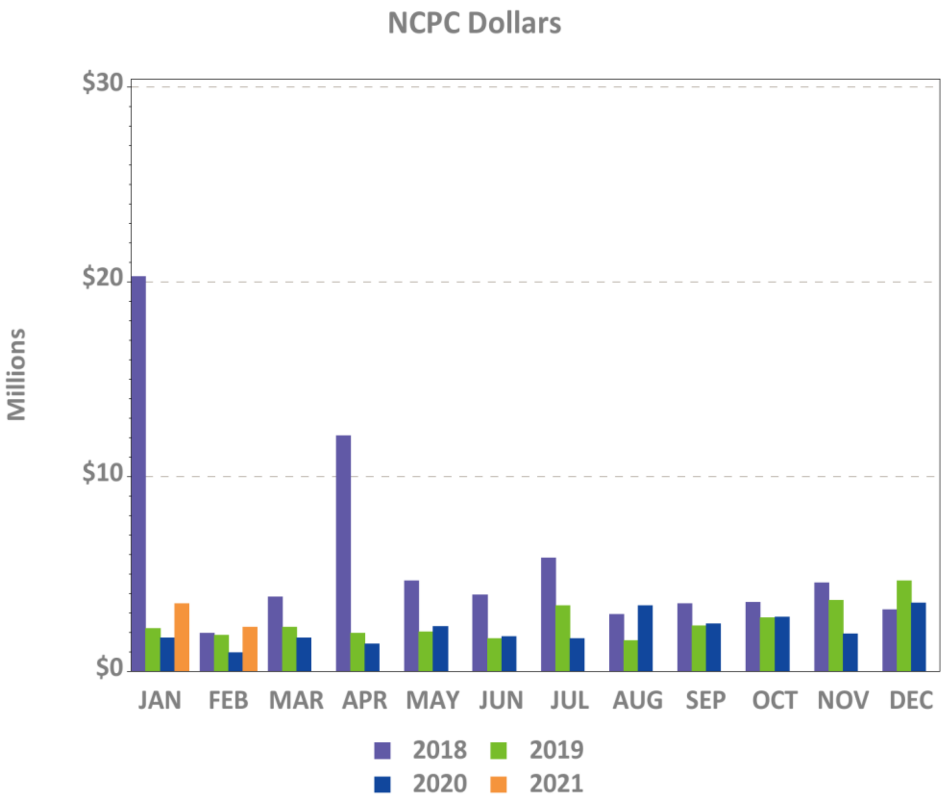
Definitions

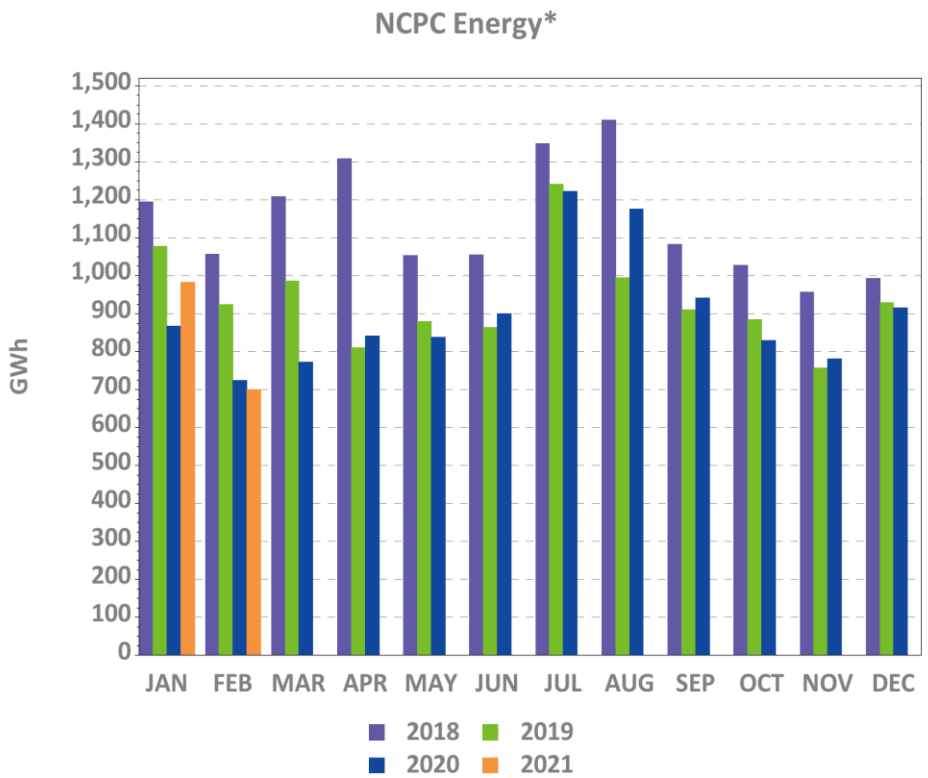
1^{st} Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2^{nd} Contingency NCPC Payments	Reliability costs paid to resources providing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

Charge Allocation Key

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

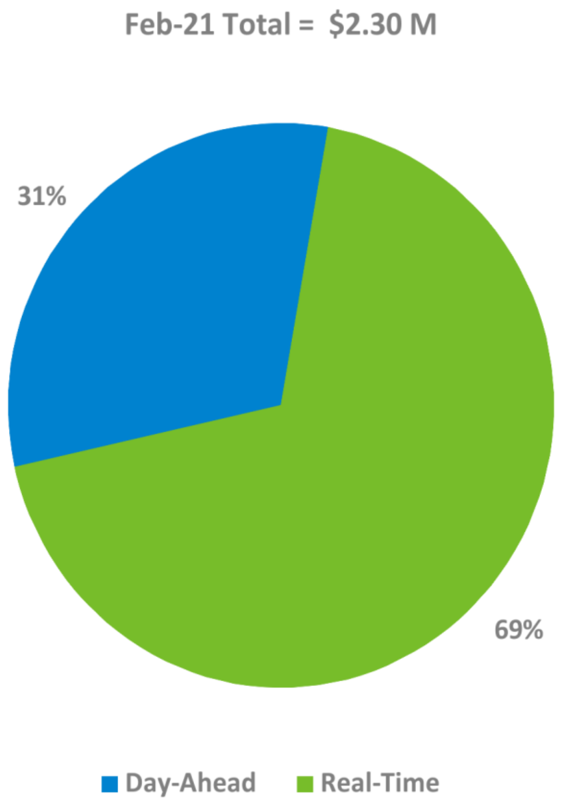
Year-Over-Year Total NCPC Dollars and Energy



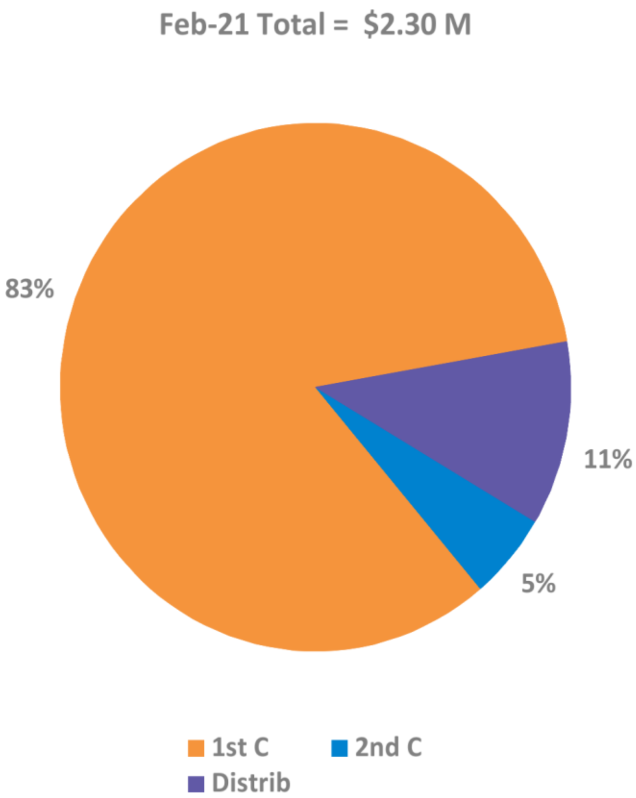


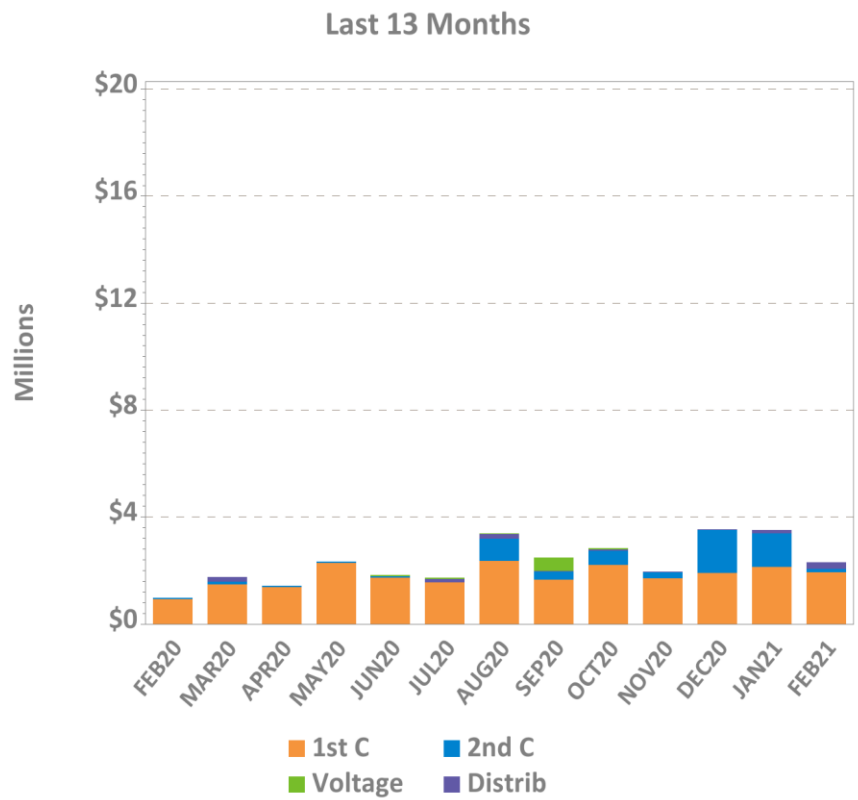
* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

DA and RT NCPC Charges



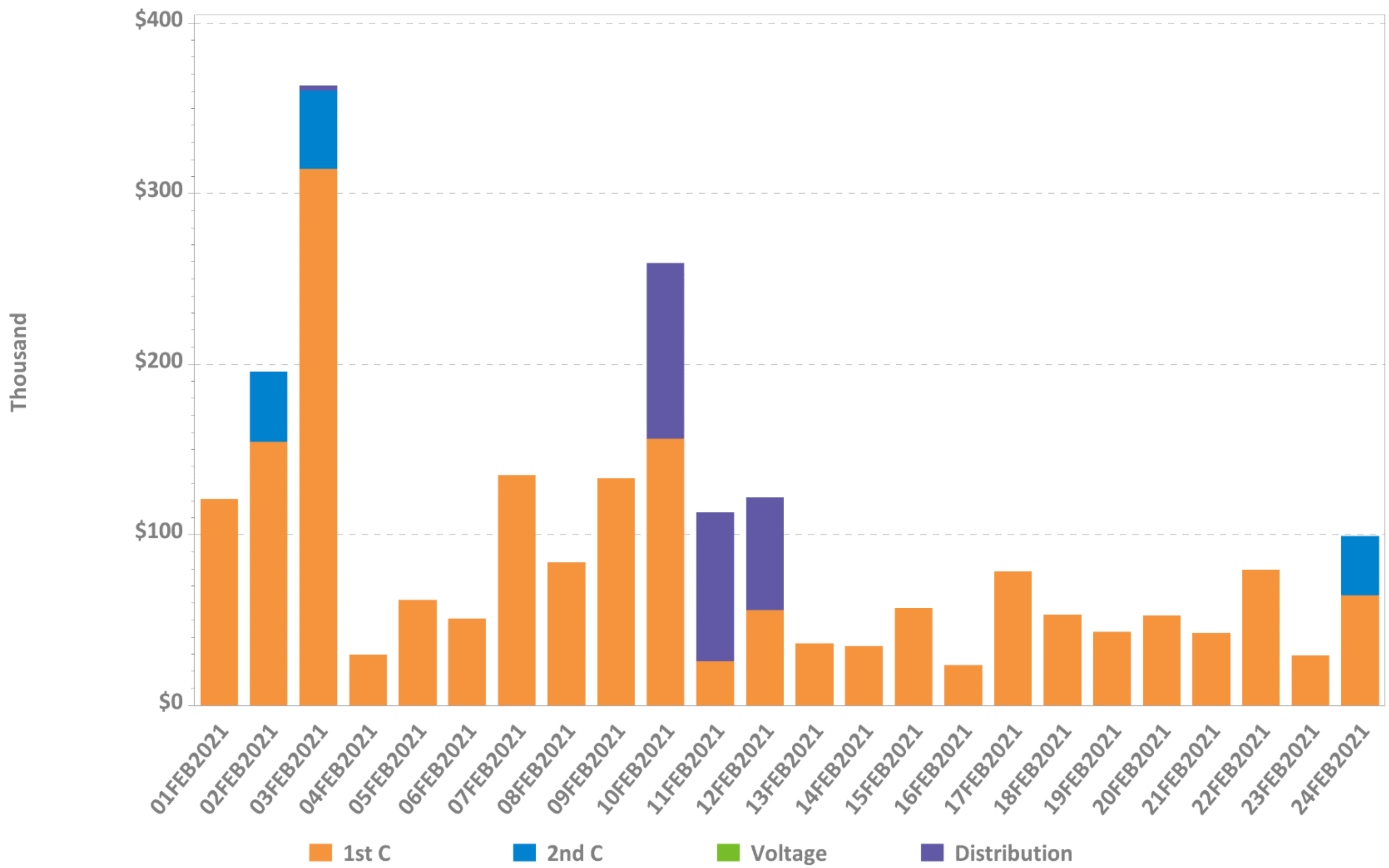
NCPC Charges by Type



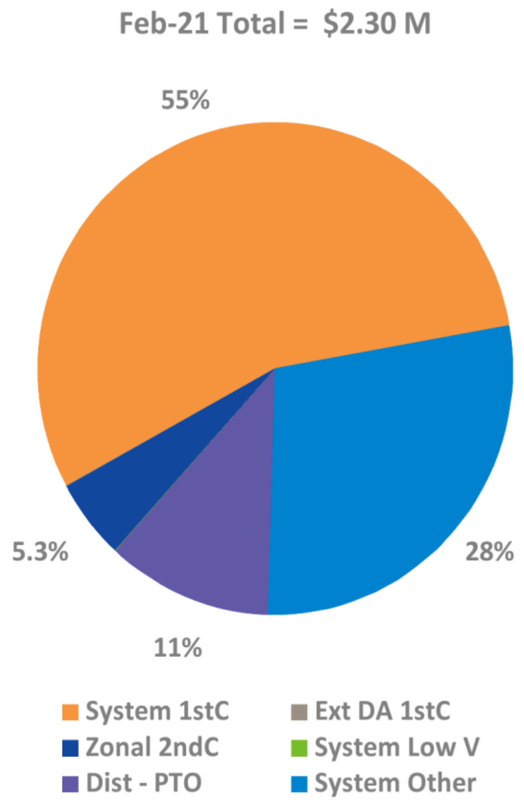


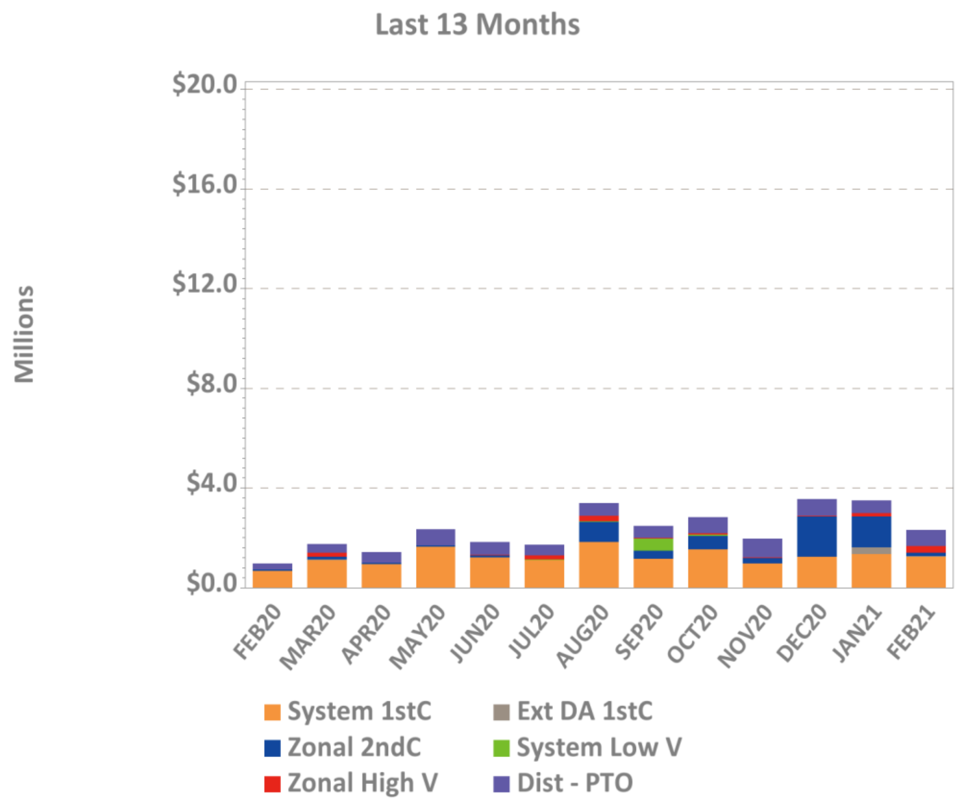
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



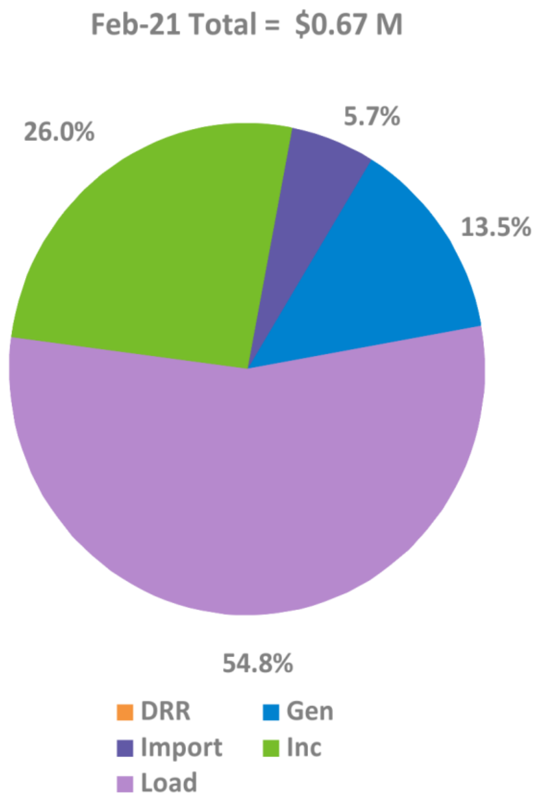
NCPC Charges by Allocation

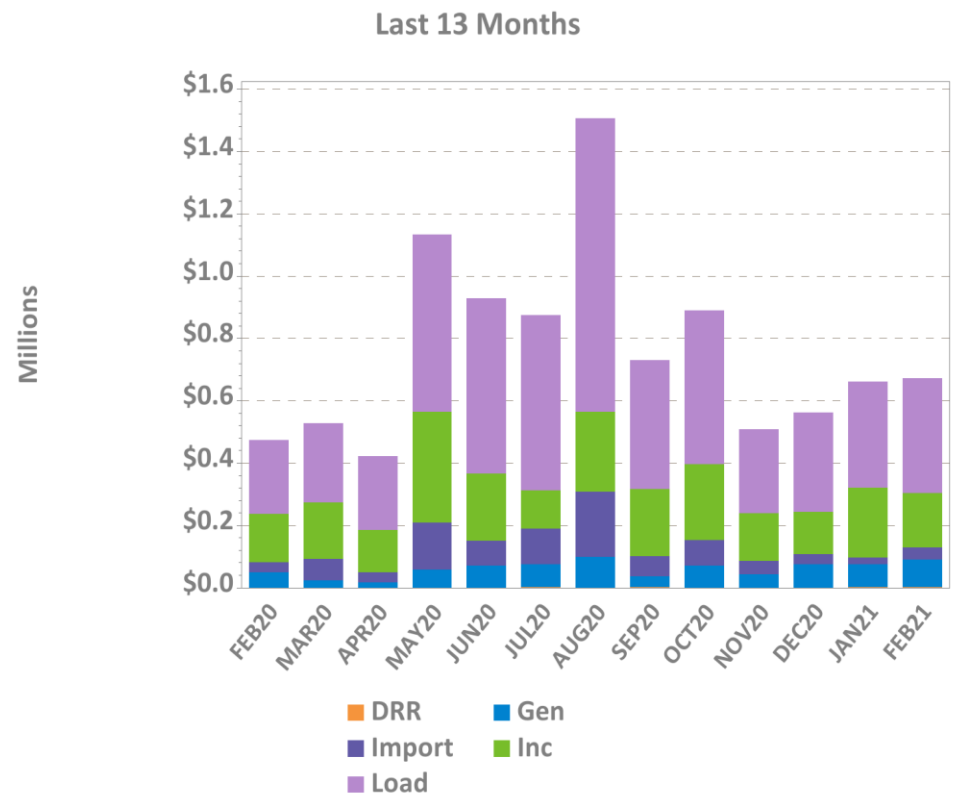




Note: ‘System Other’ includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

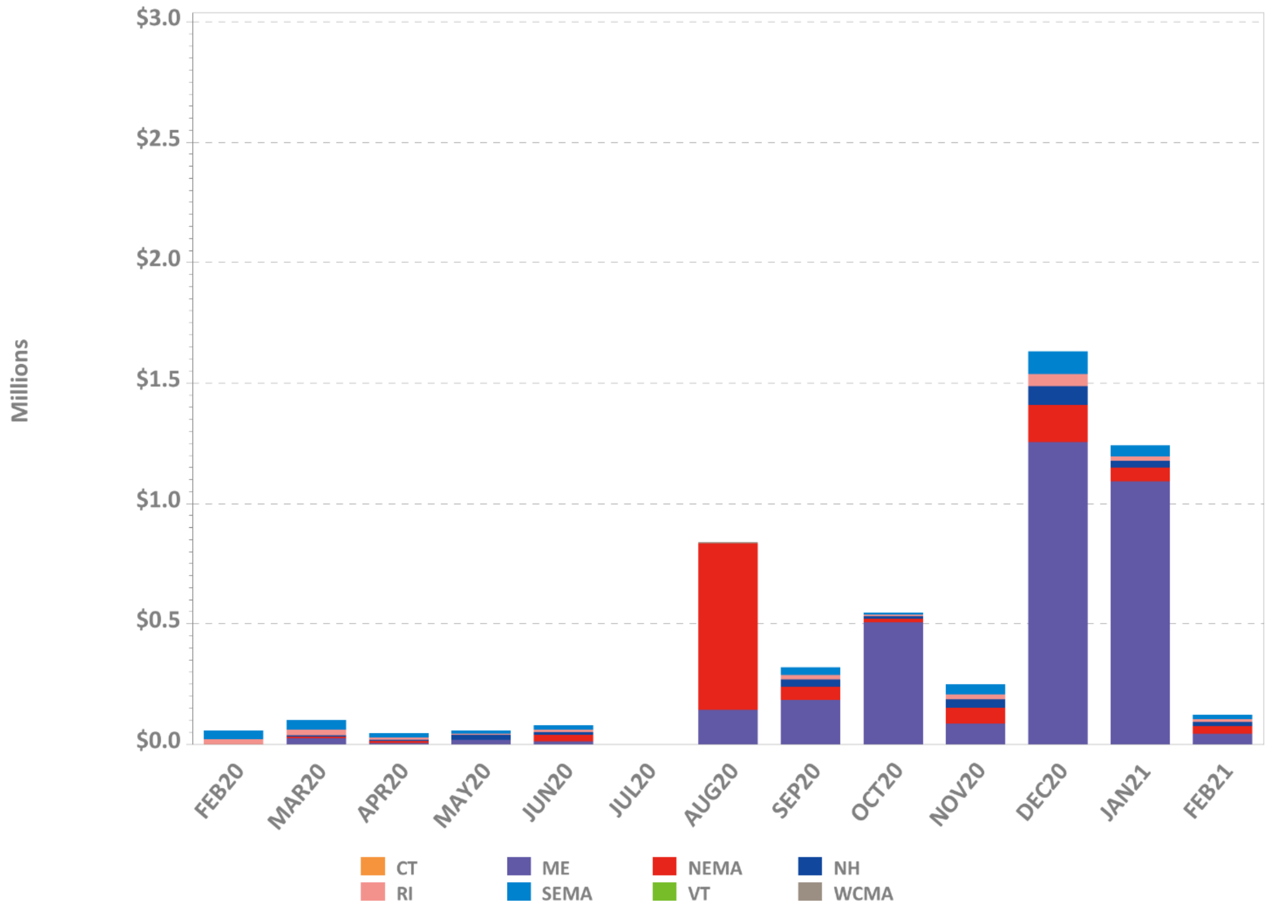
RT First Contingency Charges by Deviation Type





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

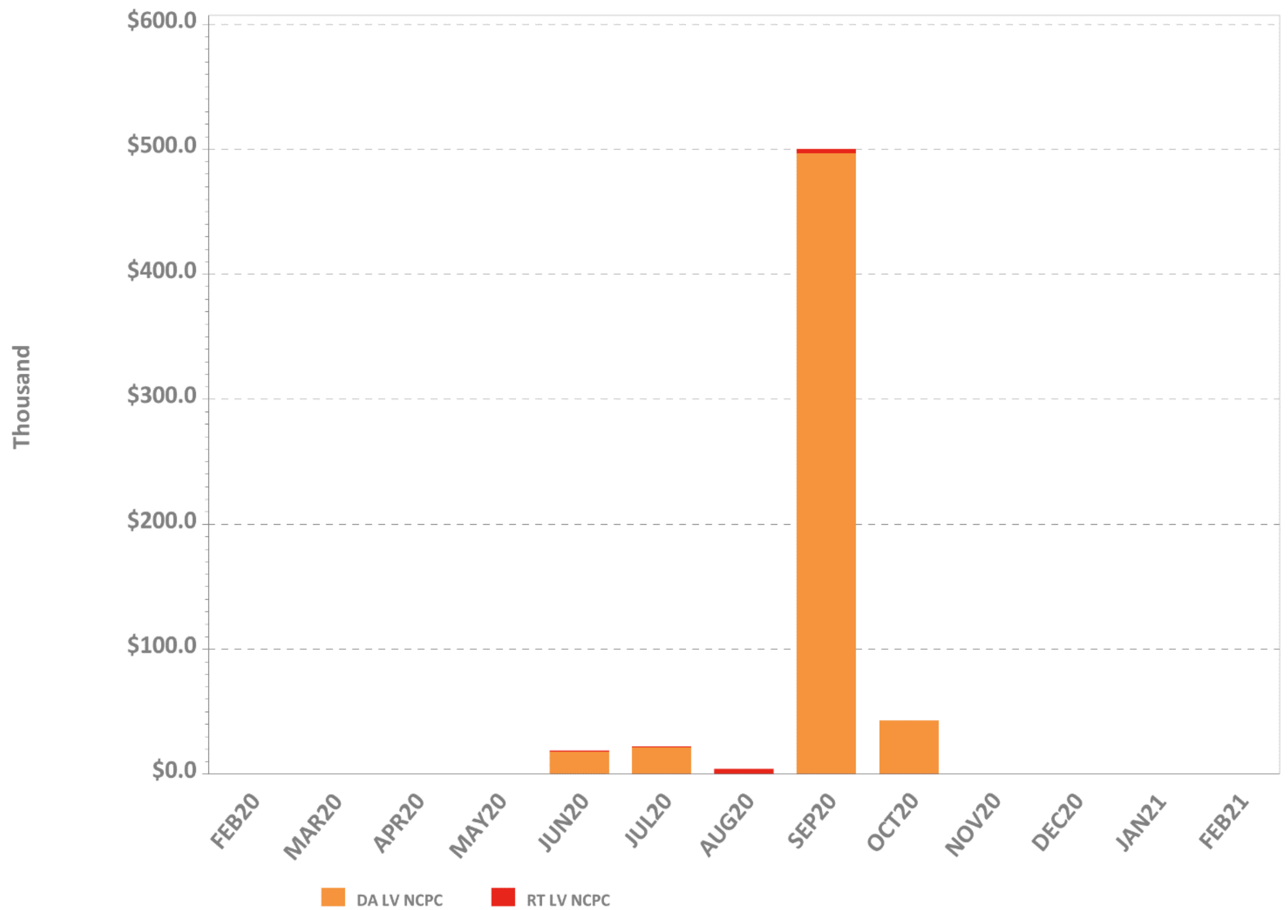
LSCPR Charges by Reliability Region



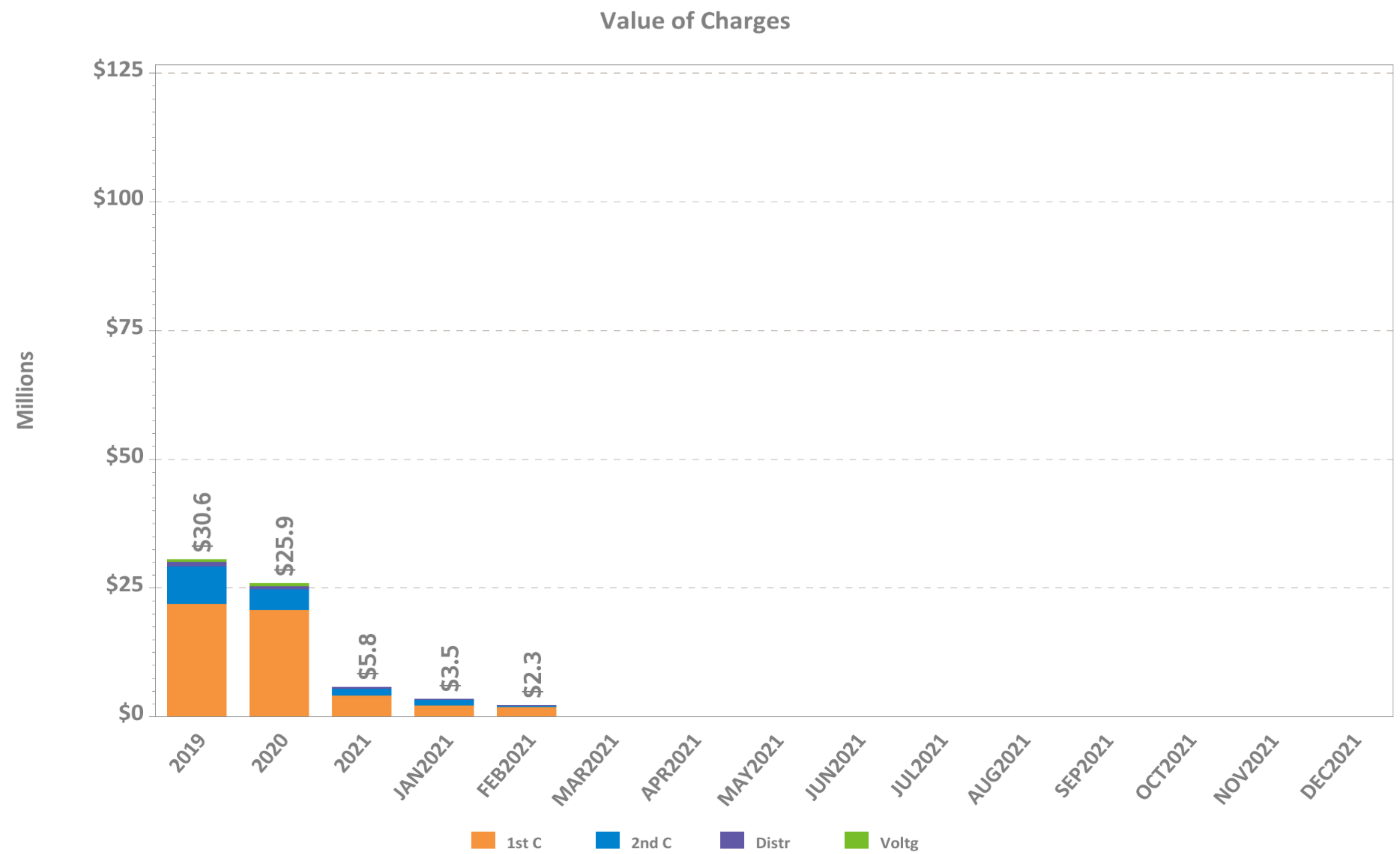
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

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

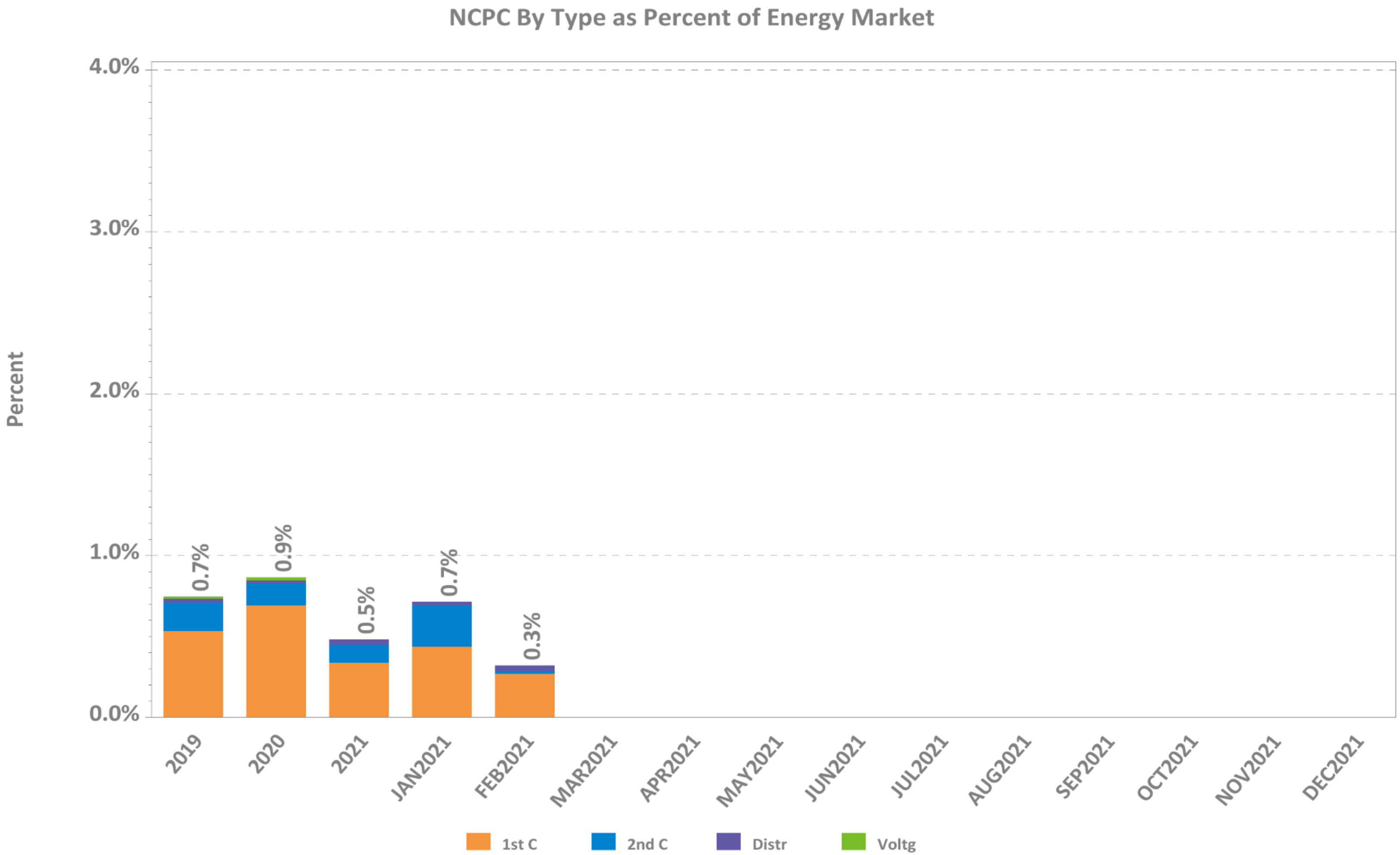
NCPC Charges for Voltage Support and High Voltage Control



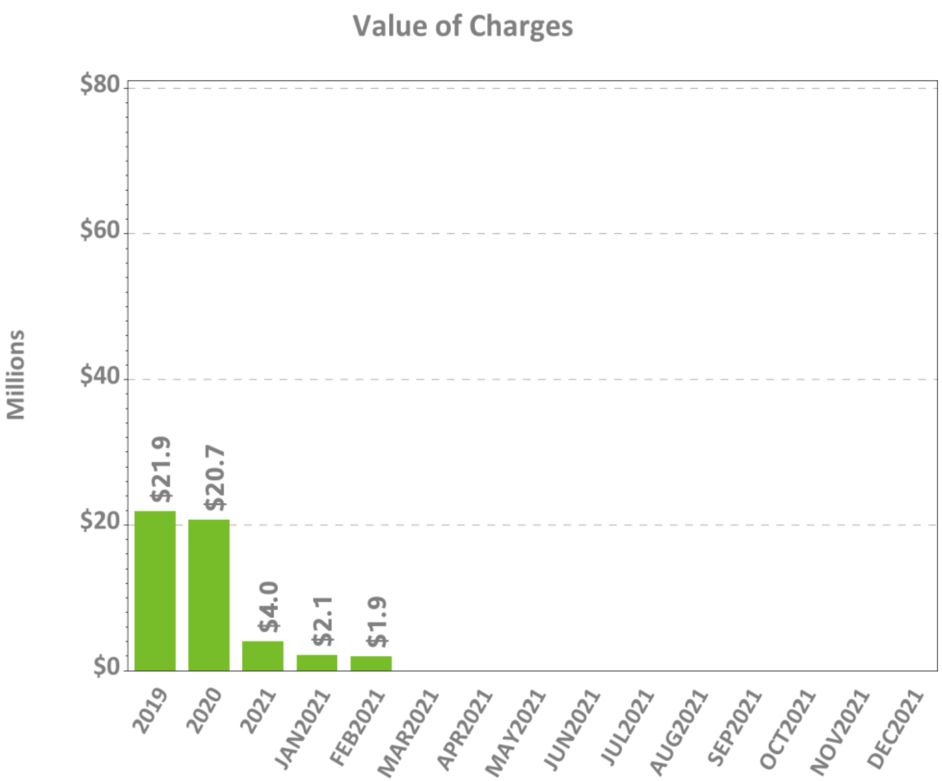
NCPC Charges by Type

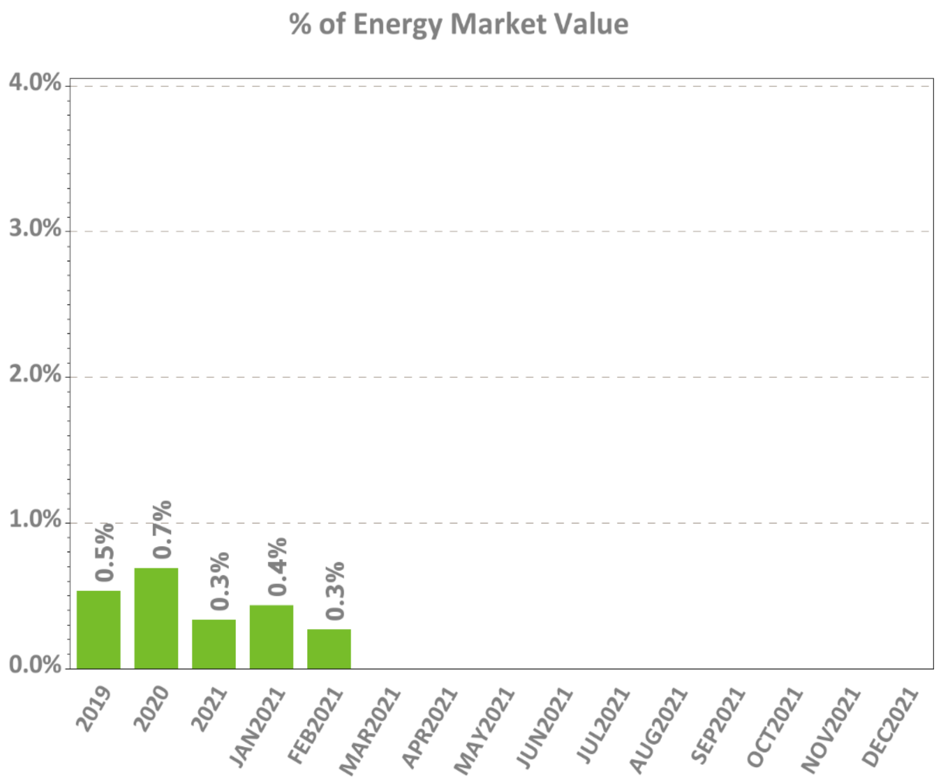


NCPC Charges as Percent of Energy Market



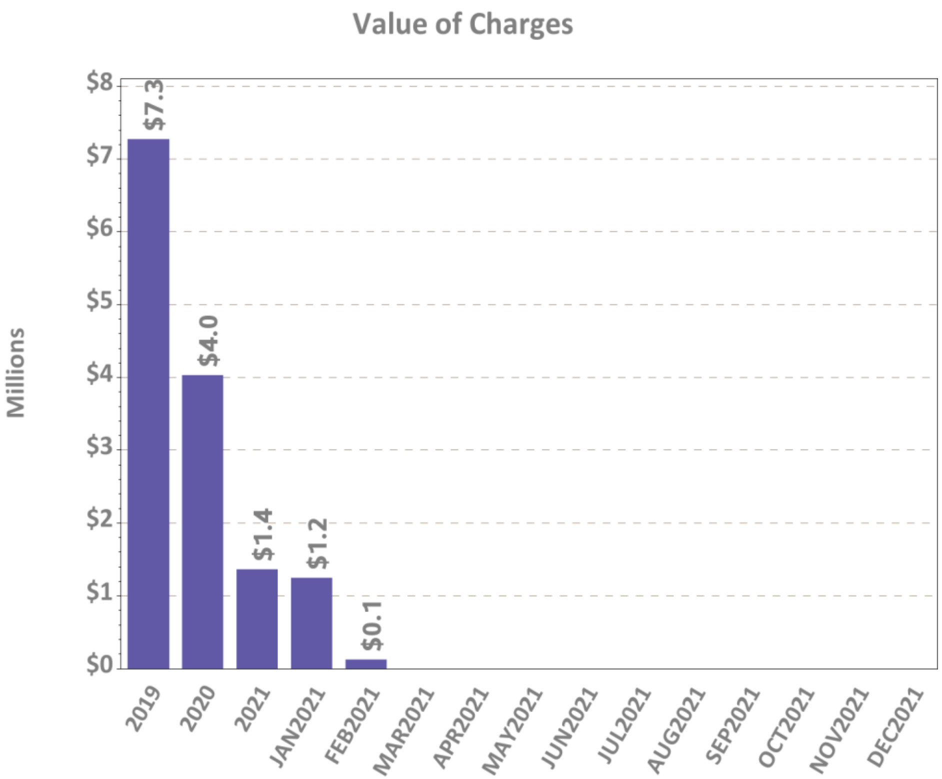
First Contingency NCPC Charges

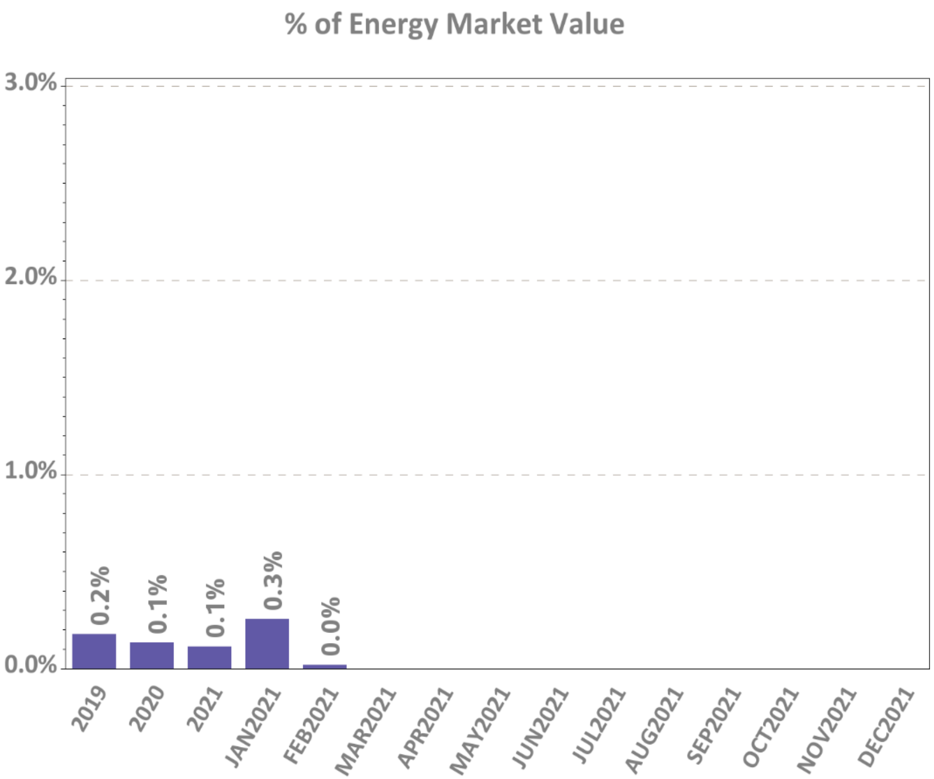




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

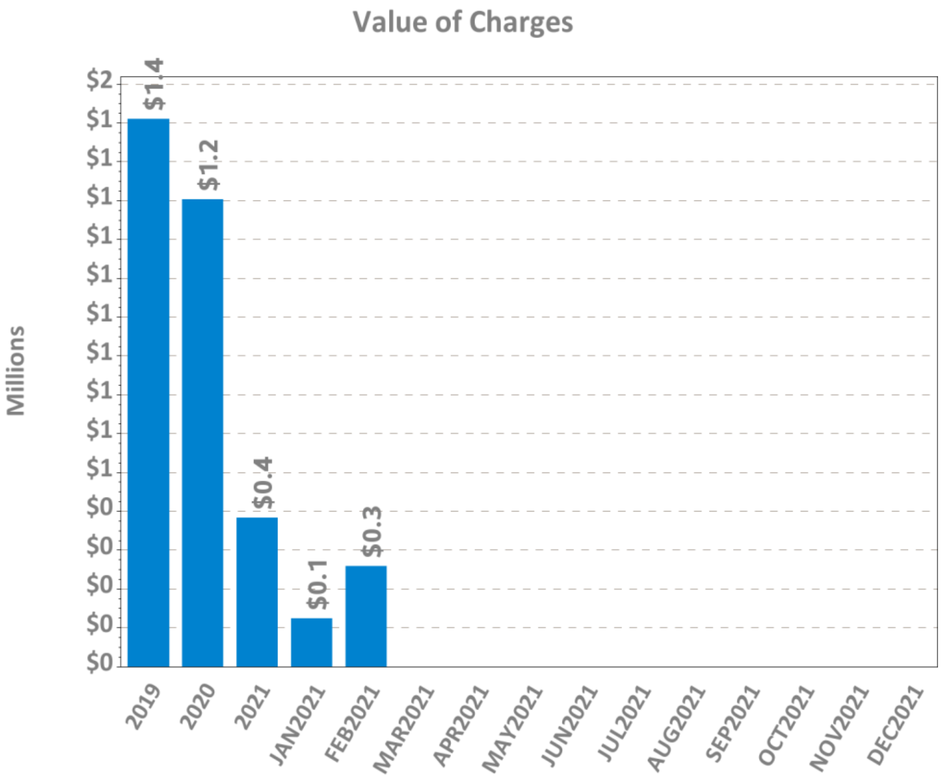
Second Contingency NCPC Charges

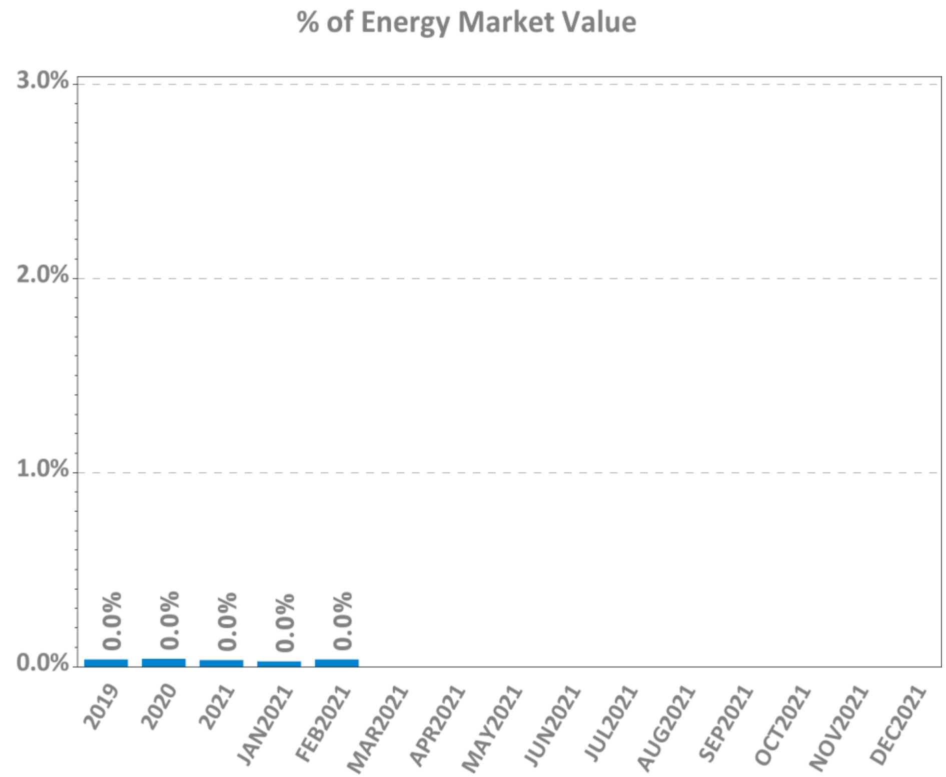




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

Voltage and Distribution NCPC Charges





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

DA vs. RT Pricing

The following slides outline:

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

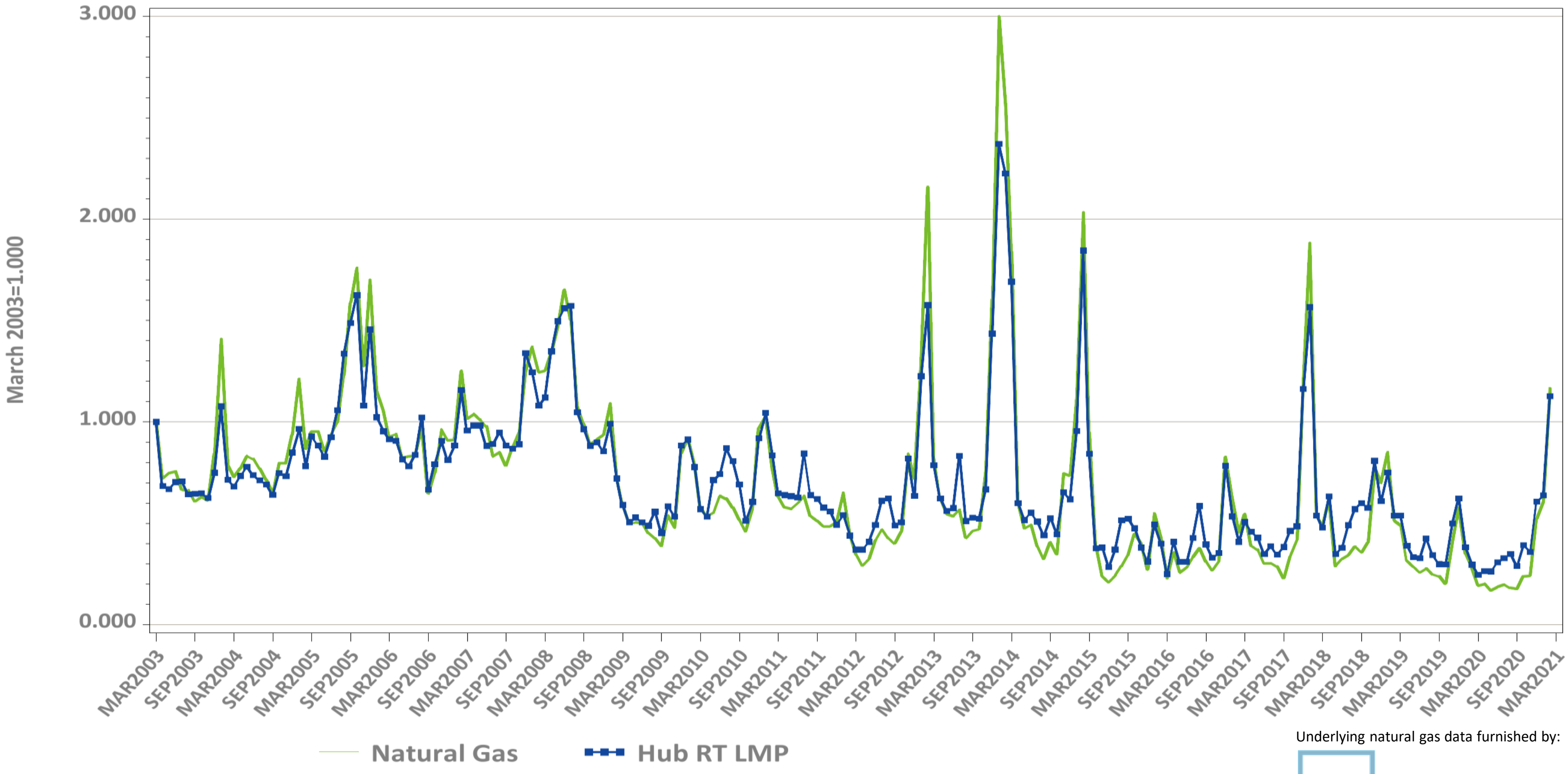
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 2019	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$31.54	$30.72	$30.76	$31.20	$30.67	$31.19	$31.51	$31.24	$31.22
Real-Time	$30.92	$30.26	$30.12	$30.70	$30.05	$30.61	$30.80	$30.68	$30.67
RT Delta %	-2.0%	-1.5%	-2.1%	-1.6%	-2.0%	-1.9%	-2.2%	-1.8%	-1.8%
Year 2020	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Day-Ahead	$23.62	$22.59	$23.27	$23.50	$22.76	$23.27	$23.57	$23.30	$23.32
Real-Time	$23.62	$22.91	$23.23	$23.54	$22.90	$23.29	$23.56	$23.37	$23.38
RT Delta %	0.0%	1.4%	-0.2%	0.2%	0.6%	0.1%	-0.1%	0.3%	0.3%

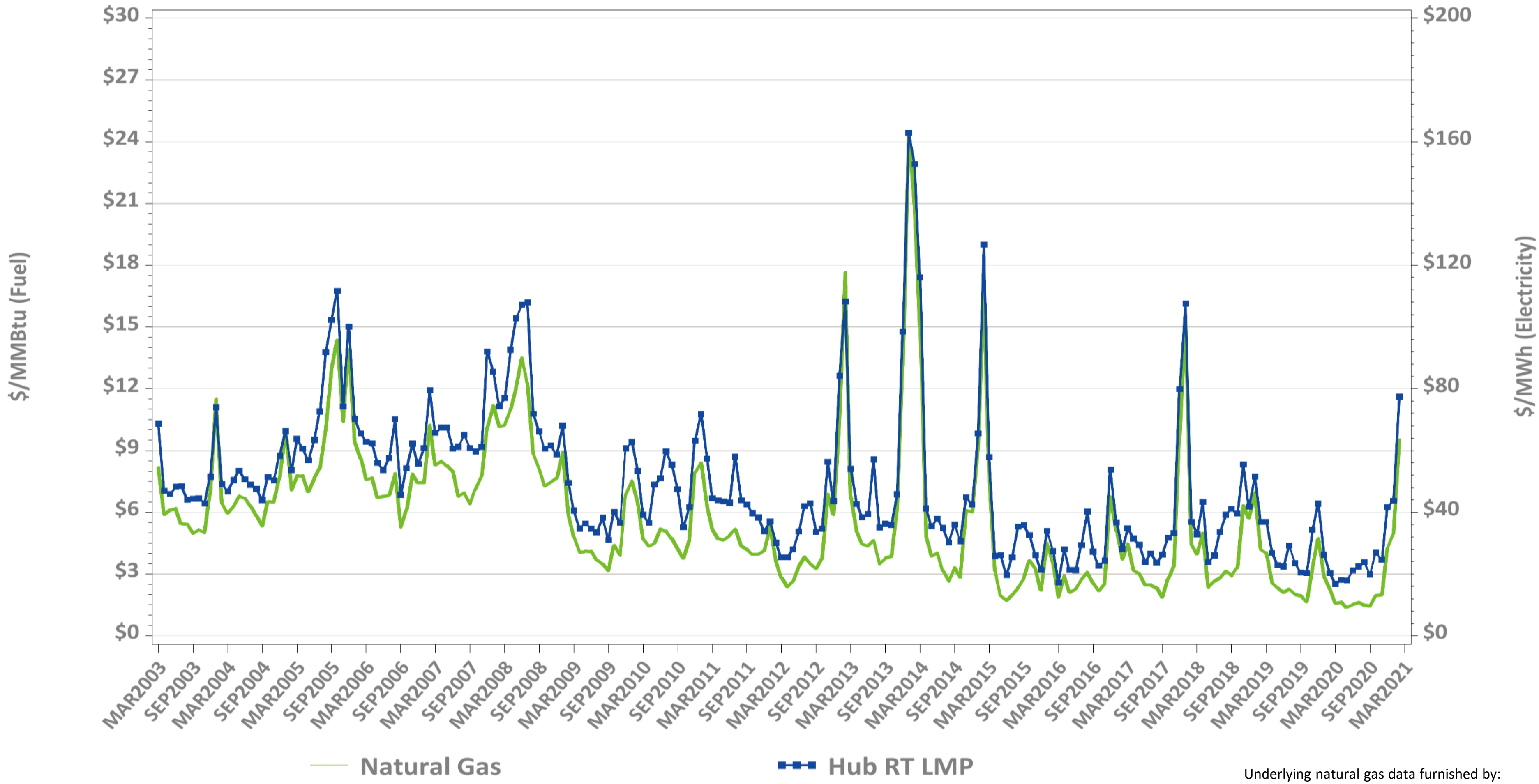
February-20	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$23.31	$22.34	$23.14	$23.27	$22.64	$23.01	$23.26	$23.04	$23.06
Real-Time	$20.53	$19.80	$20.34	$20.53	$19.98	$20.29	$20.50	$20.29	$20.32
RT Delta %	-11.9%	-11.4%	-12.1%	-11.8%	-11.8%	-11.8%	-11.9%	-11.9%	-11.9%
February-21	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Day-Ahead	$80.53	$77.91	$79.83	$80.29	$78.93	$80.42	$80.64	$80.10	$80.15
Real-Time	$77.90	$75.11	$76.97	$77.53	$76.18	$77.60	$77.91	$77.35	$77.42
RT Delta %	-3.3%	-3.6%	-3.6%	-3.4%	-3.5%	-3.5%	-3.4%	-3.4%	-3.4%
Annual Diff.	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Yr over Yr DA	245.5%	248.7%	245.0%	245.0%	248.6%	249.5%	246.7%	247.7%	247.6%
Yr over Yr RT	279.4%	279.4%	278.4%	277.6%	281.3%	282.4%	280.1%	281.2%	281.1%

Monthly Average Fuel Price and RT Hub LMP Indexes



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

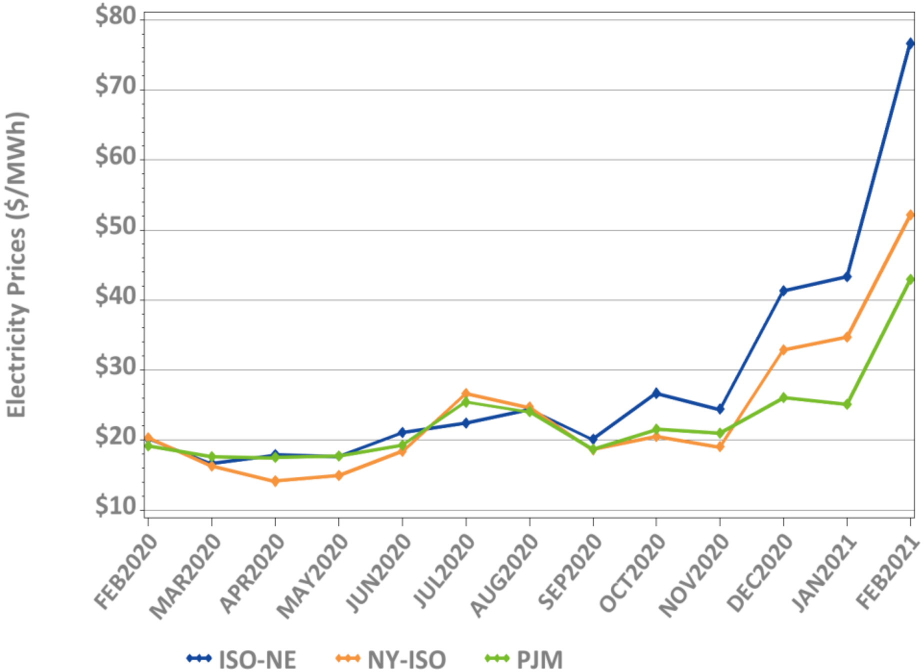
Monthly Average Fuel Price and RT Hub LMP



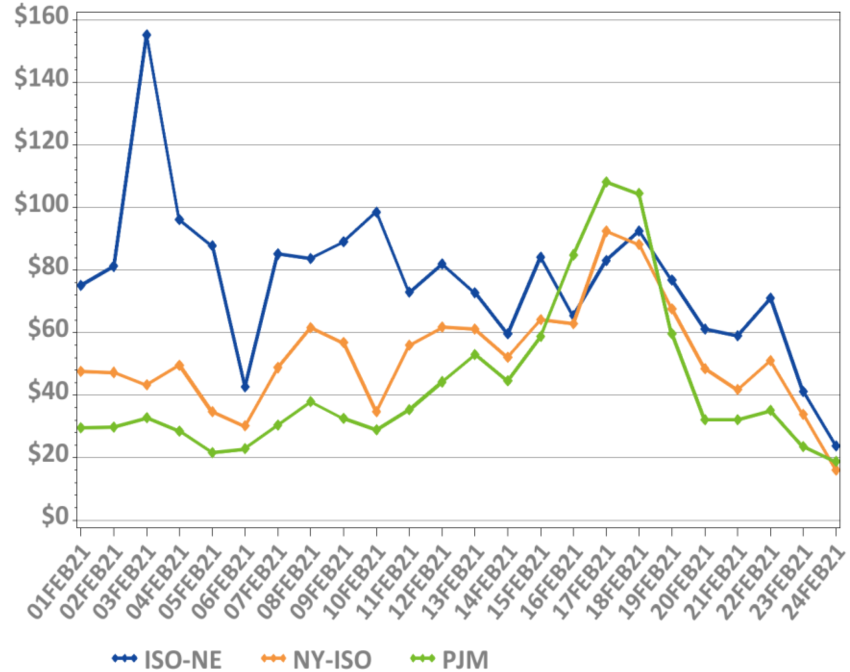
Underlying natural gas data furnished by:

ice Global markets in clear view

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

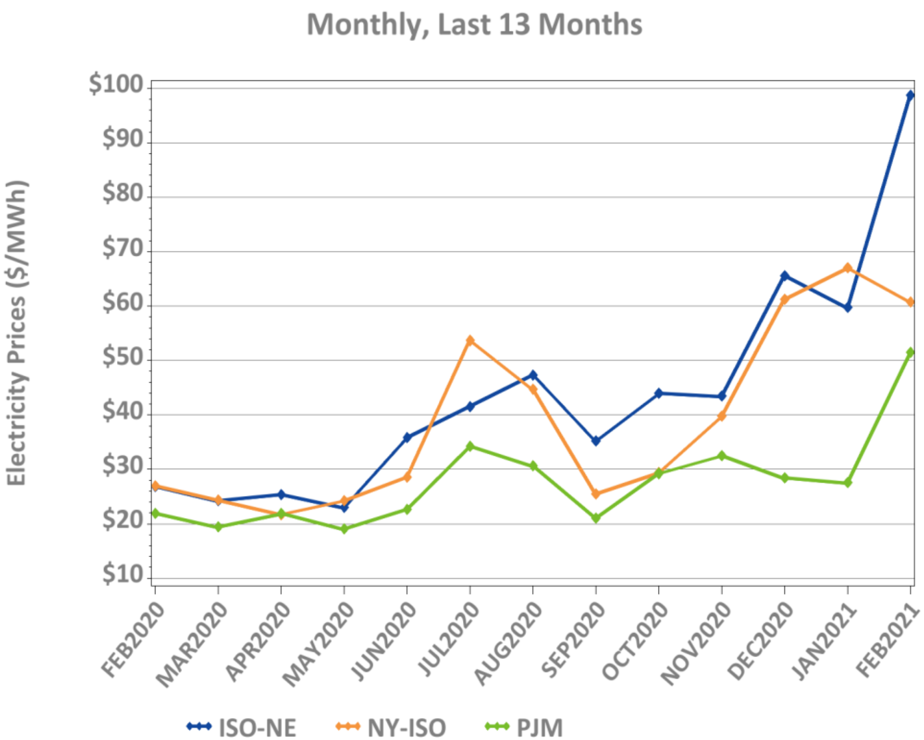


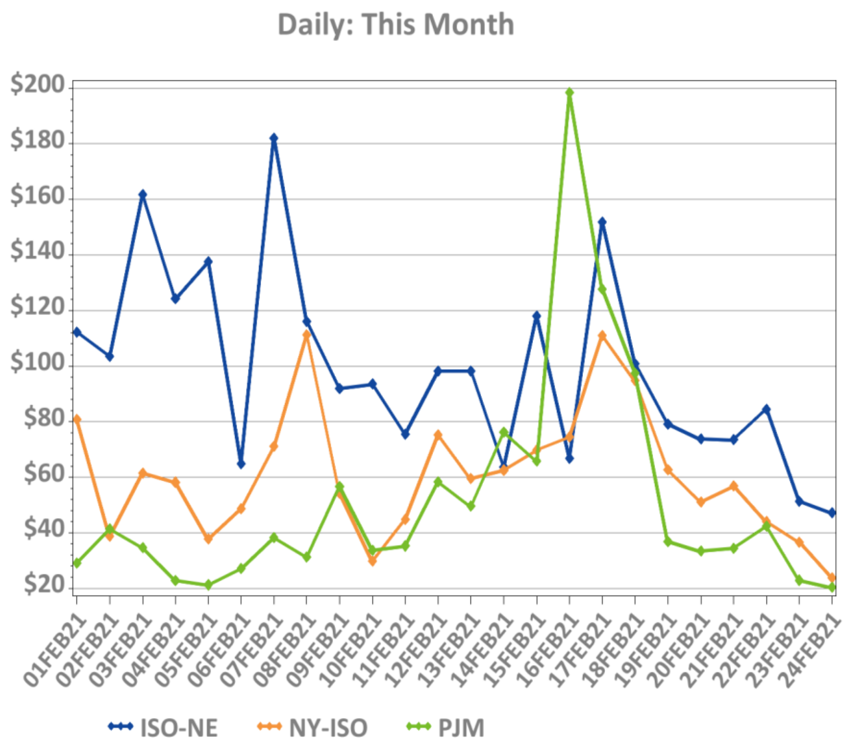
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

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





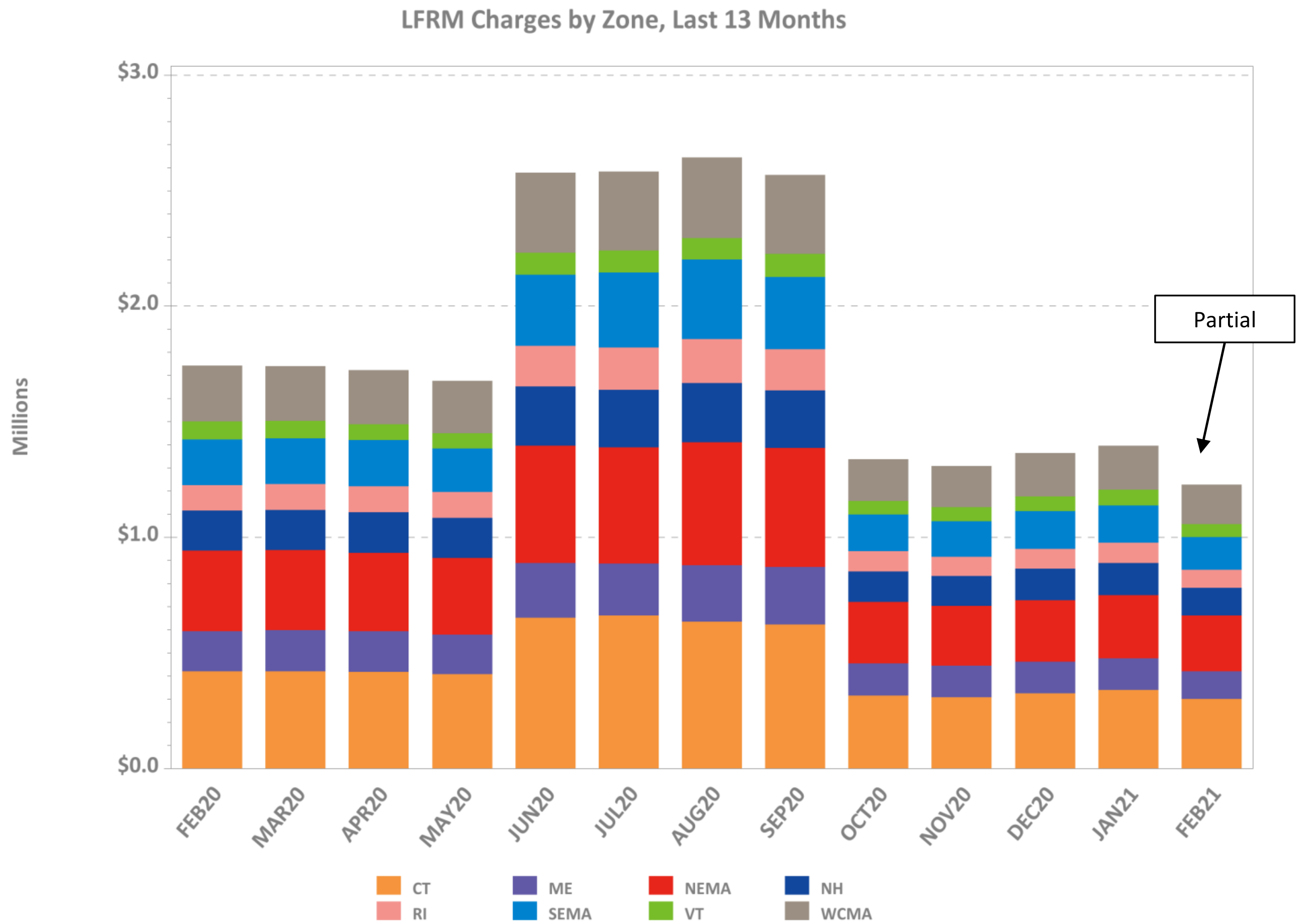
***Forecasted New England daily peak hours reflected**

Reserve Market Results – February 2021

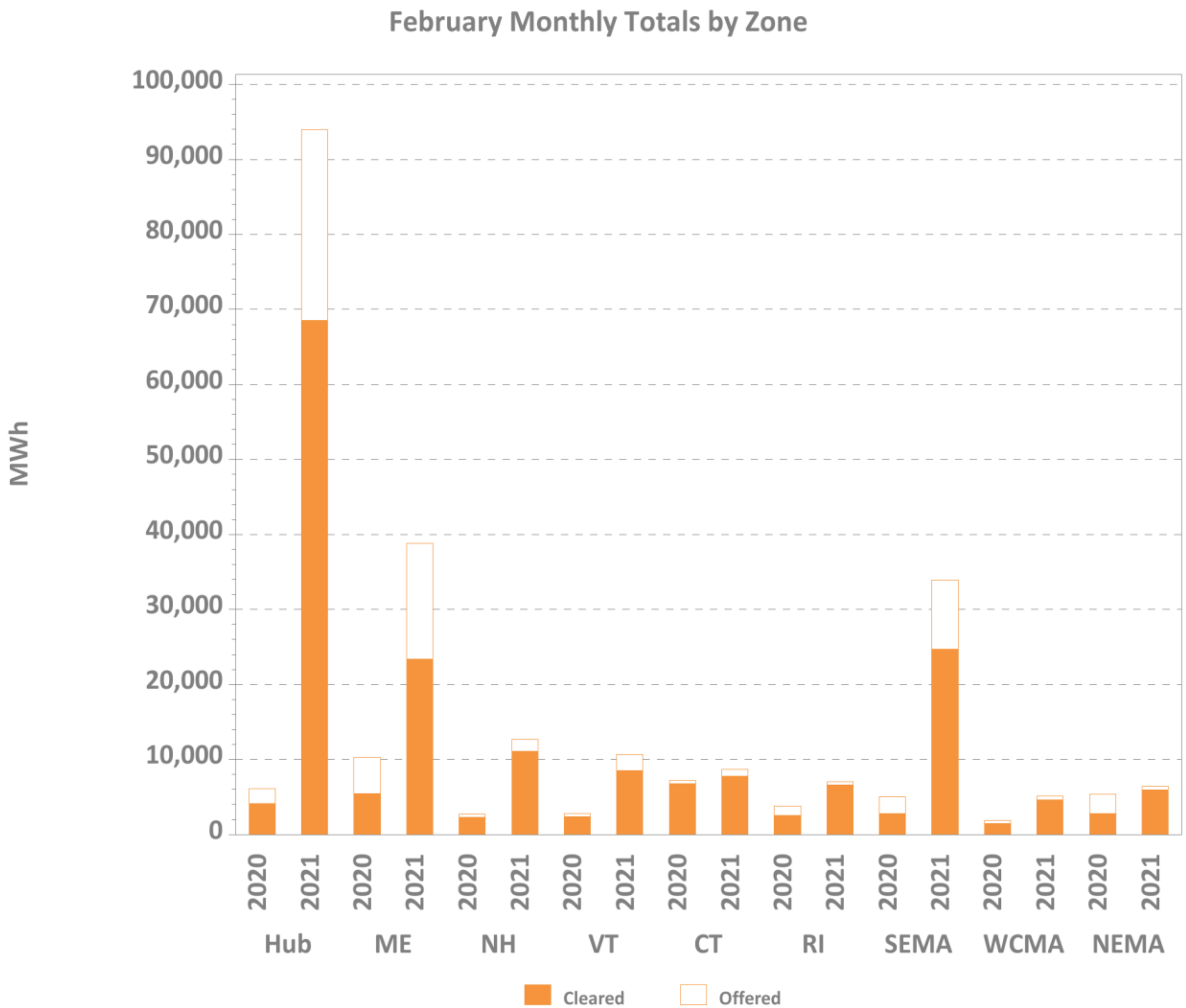
- Maximum potential Forward Reserve Market payments of $1.3M were reduced by credit reductions of $22K, failure-to-reserve penalties of $33K, and no failure-to-activate penalties, resulting in a net payout of $1.2M or 96% of maximum
  - Rest of System: $0.94M/1M (95%)
  - Southwest Connecticut: $0.04M/0.04M (100%)
  - Connecticut: $0.25M/0.25M (99%)
- $506K total Real-Time credits were not reduced by any Forward Reserve Energy Obligation Charges for a net of $506K in Real-Time Reserve payments
  - Rest of System: 154 hours, $351K
  - Southwest Connecticut: 154 hours, $90K
  - Connecticut: 154 hours, $17K
  - NEMA: 154 hours, $48K

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

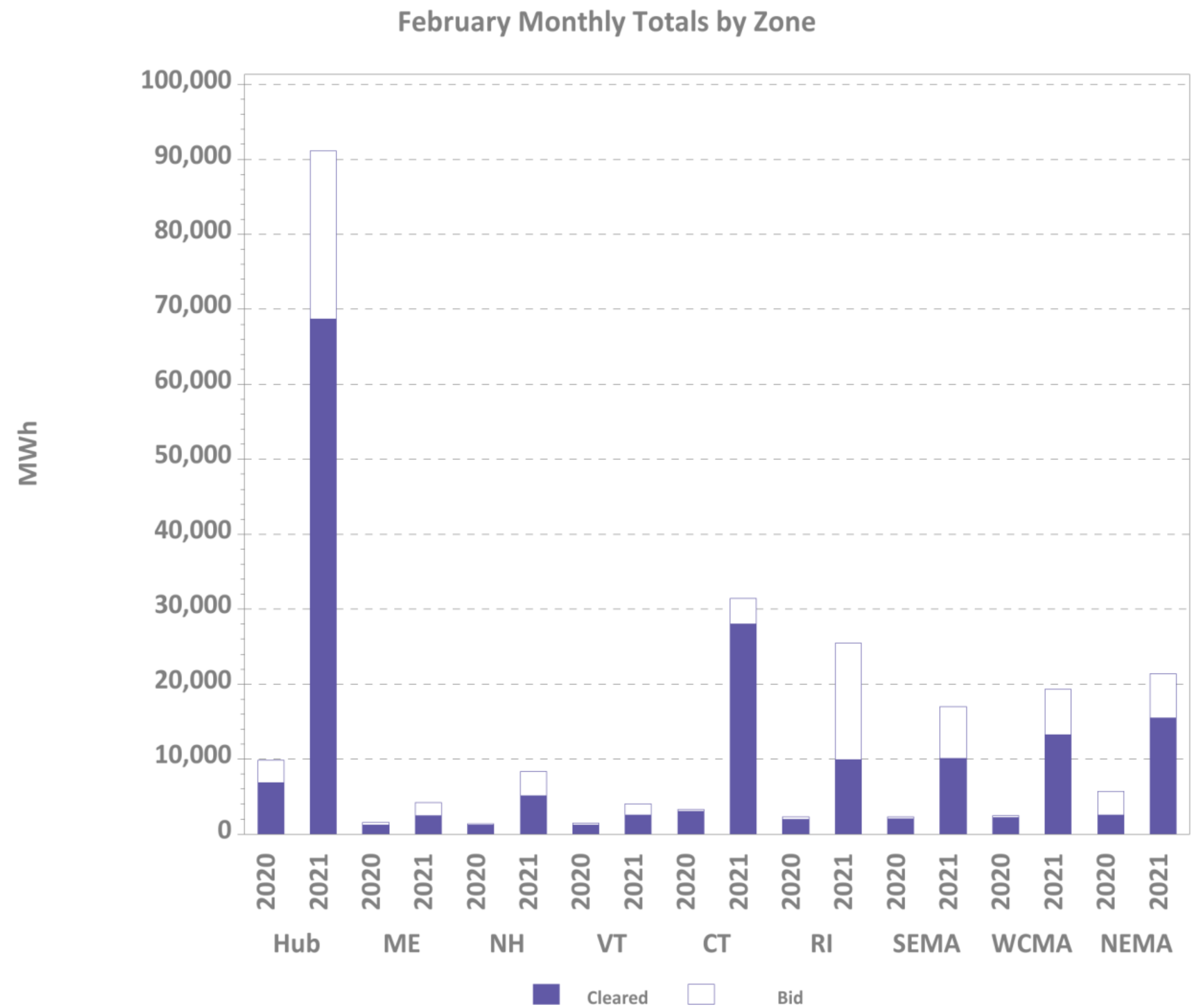
LFRM Charges to Load by Load Zone ($)



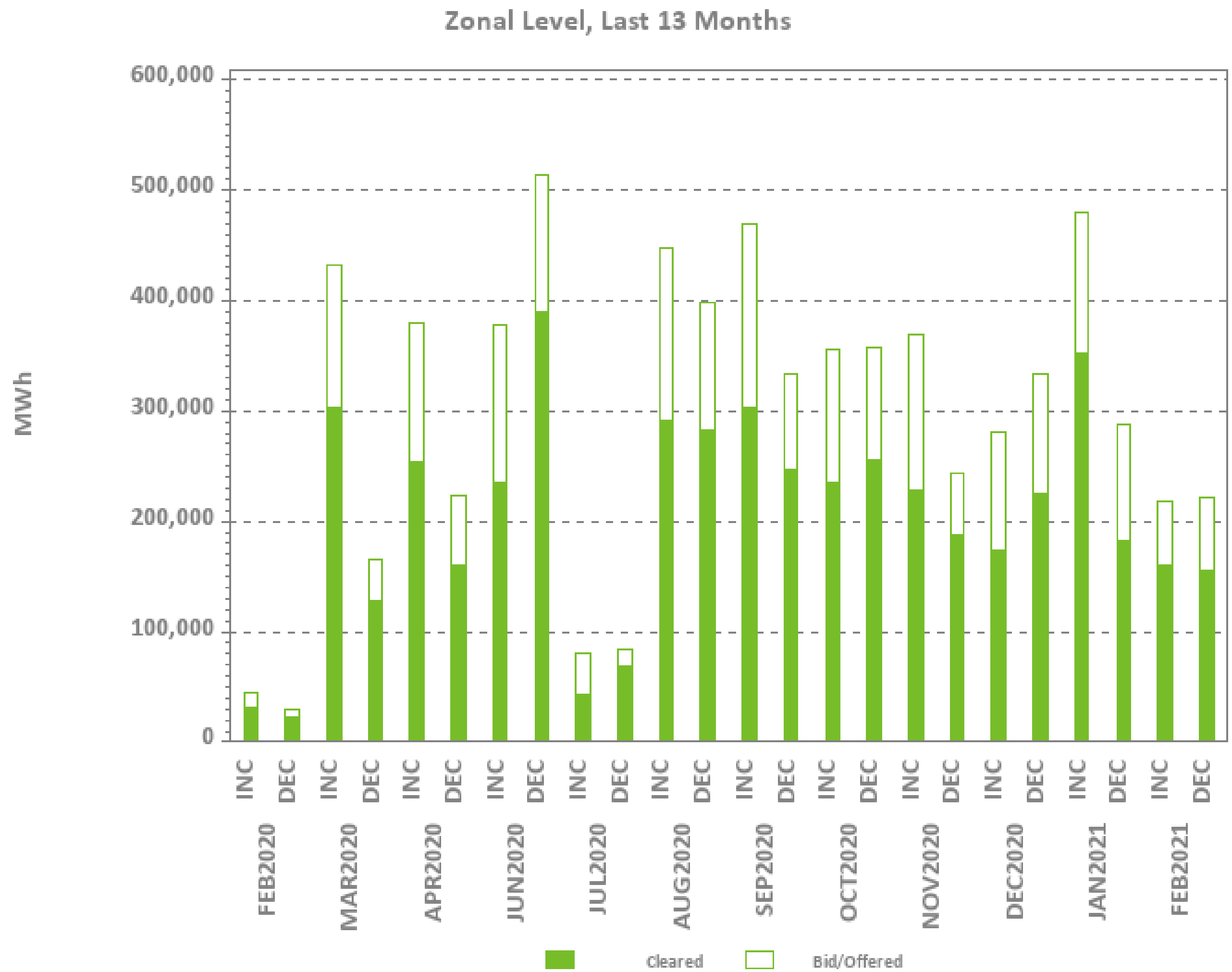
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

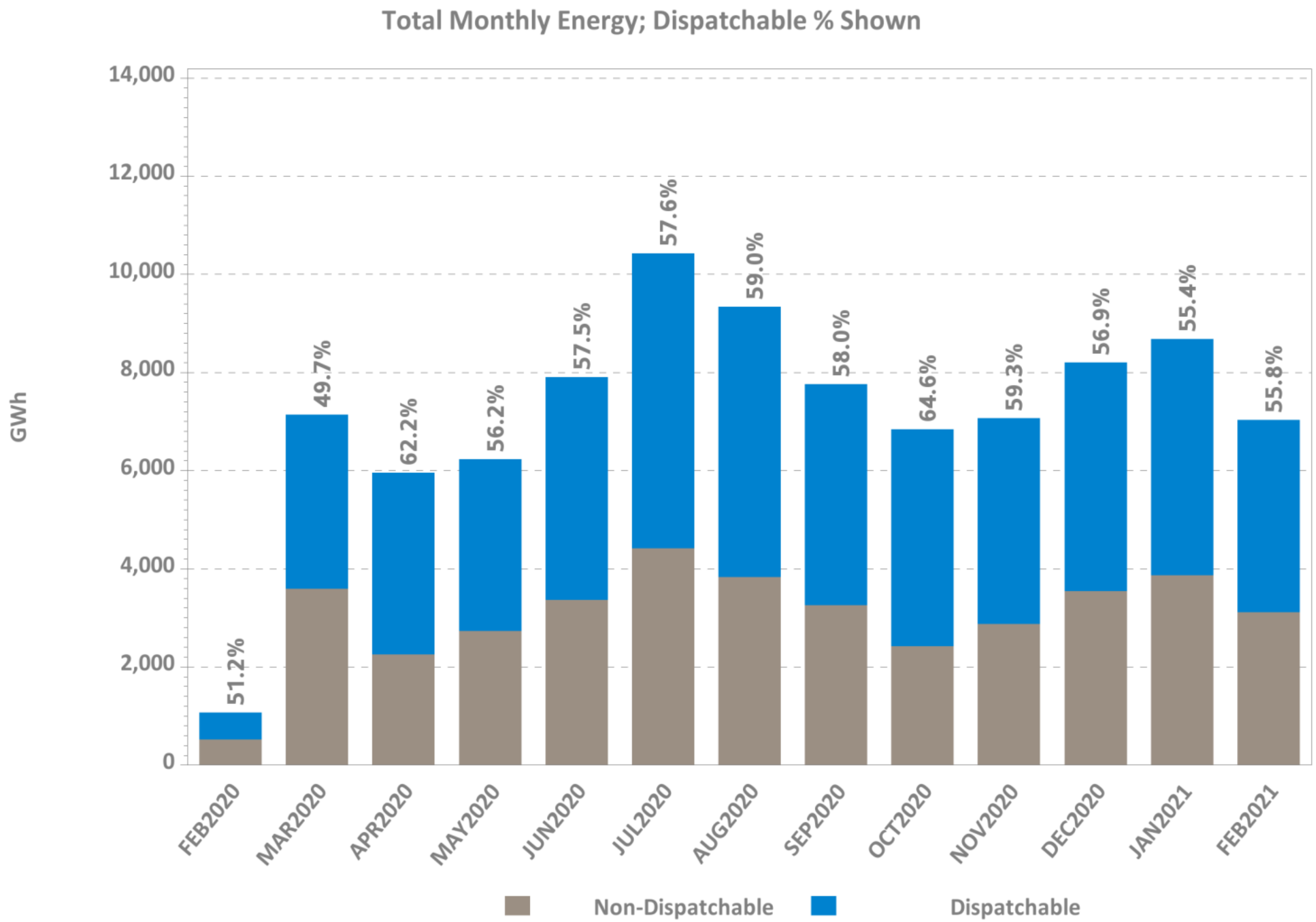


Total Increment Offers and Decrement Bids



Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation



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

REGIONAL SYSTEM PLAN (RSP)

Regional System Plan (RSP)

- 2021 is an RSP publication year (RSP21)
- Goal is to improve value and usability of the RSP report
  - The ISO received valuable stakeholder feedback as part of the spring 2020 survey
- Target is for RSP21 to be 50% shorter in length than RSP19
  - Static information found in the RSP to be moved to the ISO-NE website
  - Dynamic information found in the RSP to be included in the report but at a high level
- ISO will improve the reporting of information related to the New England regional system planning process with:
  - Better utilization of the ISO-NE website
  - More frequent reporting
  - Tables/graphics in a format that is easily downloadable
- RSP21 Public Meeting date is set for October 6
  - Venue and format have yet to be decided

Planning Advisory Committee (PAC)

- March 17 PAC Meeting Agenda Topics*
  - Lower Maine 2030 Needs Assessment Results
  - FCA 16 Zonal Boundary Determinations
  - RSP21 Process Kick-off
  - Western and Central Massachusetts (WCMA) 2029 Solutions Study Scope of Work
  - Cape Cod Resource Integration Study Preliminary Results
  - Storage in Transmission Planning Studies
  - Draft 2021 CELT Load Forecast Update
  - NPCC Directory #1 Asset Condition Update - Phase 3-5
  - Regional System Plan Transmission Projects and Asset Condition March 2021 Update
  - New Hampshire 115 kV Laminate Structure Replacements

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

Transmission Planning for the Clean-Energy Transition

- On 9/24/20 the ISO initiated discussions with the PAC about proposed refinements to study assumptions that better reflect long-term trends, such as increased amounts of distributed-energy resources (primarily solar PV), offshore wind generation, and battery energy storage
- A follow-up presentation at the 11/19/20 PAC meeting outlined a proposal for a pilot study, with the following goals:
  - Explore transmission reliability concerns that may result from various system conditions possible by 2030
  - Quantify trade-offs necessary between transmission system reliability/flexibility and transmission investment cost
  - Inform future discussions on transmission planning study assumptions
- An overview of the system conditions and dispatch assumptions for the pilot study was discussed at the 12/16/20 and 1/21/21 PAC meetings
- Study work is in progress, with results expected in Q2

Economic Studies

- 2020 Economic Study Request
  - Study proponent is National Grid
  - Study simulations are complete, and results have been presented to PAC
    - Additional sensitivities may be addressed as part of the Future Grid Reliability Study
    - Ancillary Services simulations will not be performed
    - Report to be completed by June 1
- 2021 Economic Study requests are due April 1
  - Submitted in accordance with Attachment K, Section 4.1(b) of the Tariff
  - Memo to PAC was issued on February 10 outlining the process and related deadlines

Future Grid Reliability Study (FGRS)

- Phase 1
  - Studies include: Production Cost Simulations; Ancillary Services Simulations; Resource Adequacy Screen; and Probabilistic Resource Availability Analysis
  - Framework Document and supporting assumptions table, which describe study scenarios and objectives, have been developed by stakeholders
  - The ISO is working on model development by reviewing assumptions with NEPOOL
  - Production Cost Simulations to commence in the April timeframe and initial results expected in early summer
  - Phase 1 work will be submitted as a 2021 Economic Study
- Phase 2
  - Studies include: Revenue Sufficiency Analysis and Transmission Security
  - Studies will be delayed as the Pathways and 2050 Transmission studies are further defined
  - Studies likely to be performed by a consultant

2019 Electric Generator Air Emissions Report

- Report in draft form
  - The annual ISO New England *Electric Generator Air Emissions Report* provides a comprehensive analysis of New England electric generator air emissions (NO_X, SO_2, and CO_2) and a review of relevant system conditions
- Draft Report includes:
  - New England Native Generation System Emissions
    - Total (ktons)
    - Rates (lbs/MWh)
  - New England Locational Marginal Unit Marginal Emissions
    - Both unweighted and load-weighted analyses
    - Rates (lbs/MWh)
  - Does not include import emissions
- Results were presented to the Environmental Advisory Group on February 19
- Final Report to be posted in March
  - An updated Emissions Report, that includes import emissions, to be posted in the May timeframe

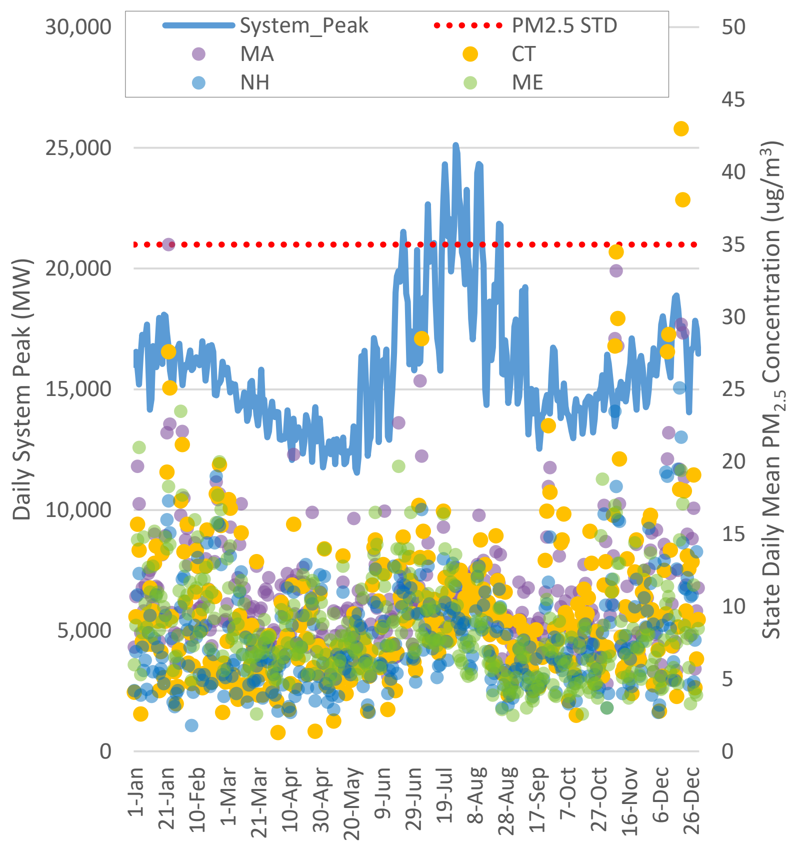
Environmental Matters – Reset on Federal Environmental Priorities; Focus on Particles

EPA Shifting Staff & Priorities in Response to Executive Orders

- EPA asked to update fine particle ($PM_{2.5}$) and other ambient air standards (O_3, NO_2), challenged as too weak
  - More stringent standards could require limiting emissions and constraining operations at fossil generators
- Chart shows 2020 daily system peak generation (MW) (left axis) vs. maximum $PM_{2.5}$ daily outdoor concentrations for some New England States (right axis)
  - All New England monitoring sites currently 12-20 micrograms per cubic meter (ug/m^3)
  - Current 24-hour standard 35 ug/m^3 (dotted red line) (right axis)
  - Health researchers recommend lowering 24-hour standard to 15-25 ug/m^3, adding monitors near power plants and other industrial sources

$PM_{2.5}$, fine particulate; O_3, ground-level ozone; NO_2, nitrogen dioxide. All emitted during combustion of fossil fuels by engines, boilers and turbines.

States Ask EPA to Reconsider 2020 Fine Particle Standard, Lower Limit



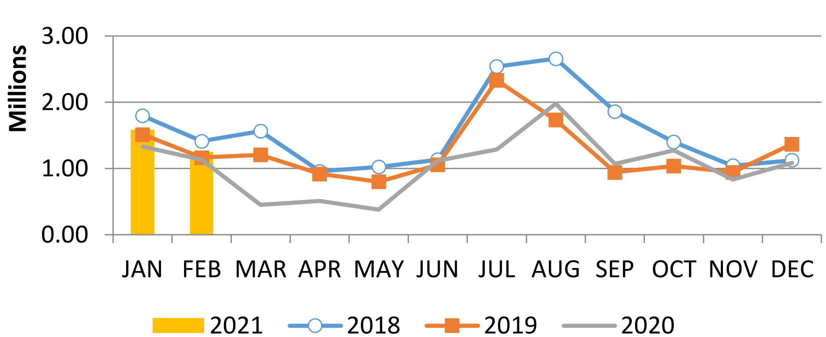
MA, CT, RI and VT joined other states petitioning EPA to withdraw 12/18/20 $PM_{2.5}$ standard, in light of health research showing harm at lower concentrations

Environmental Matters – Massachusetts CO_2 Generator Emissions Cap

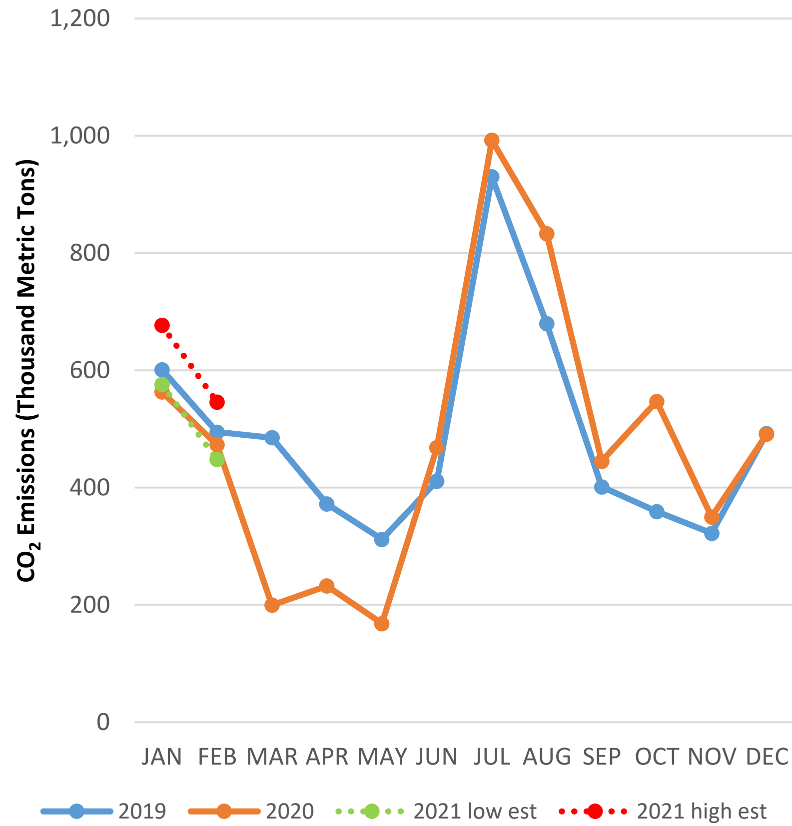
2021 CO_2 Emissions Trending Higher Than Past 1st Quarters

- YTD 2021 estimated CO_2 emissions range between 1.0 and 1.2 MMT
  - 2021 cap is 8.23 MMT
- March 11, 2021: Next GWSA auction will offer 1.6 million allowances (20% of 2021 cap)
- December 16, 2020: GWSA auction clearing price was $7.25 per metric ton

YTD Generation (MWh) (1/1-2/21)



2019-2021 Estimated Monthly Emissions (Thousand Metric Tons)



MMT – Million 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.

Southwest Connecticut (SWCT) Projects

Status as of 2/19/2021

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 2/19/2021

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)	Nov-20	4
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 2/19/2021

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 2/19/2021

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)	Feb-21	4

Southwest Connecticut Projects, cont.

Status as of 2/19/2021

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 2/19/2021

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 2/19/2021

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	Sep-20	4
Install third 115 kV line from West Walpole to Holbrook	Sep-20	4
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 2/19/2021

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	May-21	3

*Mystic to Chelsea line portion of the project is a present stage 4 as of October 2020.

Greater Boston Projects, cont.

Status as of 2/19/2021

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 2/19/2021

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 2/19/2021

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

Upgrade	Expected/ Actual In-Service	Present Stage
Construct a new 115 kV GIS switching station (Grand Army) which includes remote terminal station work at Brayton Point and Somerset substations, and the looping in of the E-183E, F-184, X3, and W4 lines	Oct-20	4
Conduct remote terminal station work at the Wampanoag and Pawtucket substations for the new Grand Army GIS switching station	Oct-20	4
Install upgrades at Brayton Point substation which include a new 115 kV breaker, new 345/115 kV transformer, and upgrades to E183E, F184 station equipment	Oct-20	4
Increase clearances on E-183E & F-184 lines between Brayton Point and Grand Army substations	Nov-19	4
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 2/19/2021

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

Upgrade	Expected/ Actual In-Service	Present Stage
Add 115 kV circuit breaker at Robinson Ave substation and re-terminate the Q10 line	Dec-21	3
Install 45.0 MVAR capacitor bank at Berry Street substation	Cancelled*	N/A
Separate the N12/M13 DCT and reconductor the N12 and M13 between Somerset and Bell Rock substations	May-25	2
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	Jun-23	2
Extend the Line 114 from the Dartmouth town line (Eversource-NGRID border) to Bell Rock substation	Dec-23	2
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 2/19/2021

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

Upgrade	Expected/ Actual In-Service	Present Stage
Build a new 115 kV line from Bourne to West Barnstable substations which includes associated terminal work	Dec-23	1
Separate the 135/122 DCT from West Barnstable to Barnstable substations	Dec-21	3
Retire the Barnstable SPS	Dec-21	3
Build a new 115 kV line from Carver to Kingston substations and add a new Carver terminal	Dec-23	1
Install a new bay position at Kingston substation to accommodate new 115 kV line	Dec-22	1
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 2/19/2021

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

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

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

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

SEMA/RI Reliability Projects, cont.

Status as of 2/19/2021

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

Upgrade	Expected/ Actual In-Service	Present Stage
Rebuild the Middleborough Gas and Electric portion of the E1 line from Bridgewater to Middleborough	Apr-19	4
Reconductor the J16S line	Jun-22	2
Replace the Kent County 345/115 kV transformer	Mar-22	2
West Medway 345 kV circuit breaker upgrades	Dec-21	3
Medway 115 kV circuit breaker replacements	Nov-20	4

Eastern CT Reliability Projects

Status as of 2/19/2021

Project Benefit: Addresses system needs in the Eastern Connecticut area

Upgrade	Expected/ Actual In-Service	Present Stage
Reconductor the L190-4 and L190-5 line sections	Dec-26	1
Install a second 345/115 kV autotransformer (4X) and one 345 kV breaker at Card substation	Mar-23	2
Upgrade Card 115 kV to BPS standards	Mar-23	2
Install one 115 kV circuit breaker in series with Card substation 4T	Mar-23	2
Convert Gales Ferry substation from 69 kV to 115 kV	Dec-23	1
Rebuild the 100 Line from Montville to Gales Ferry to allow operation at 115 kV	Dec-21	1

Eastern CT Reliability Projects, cont.

Status as of 2/19/2021

Project Benefit: Addresses system needs in the Eastern Connecticut area

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

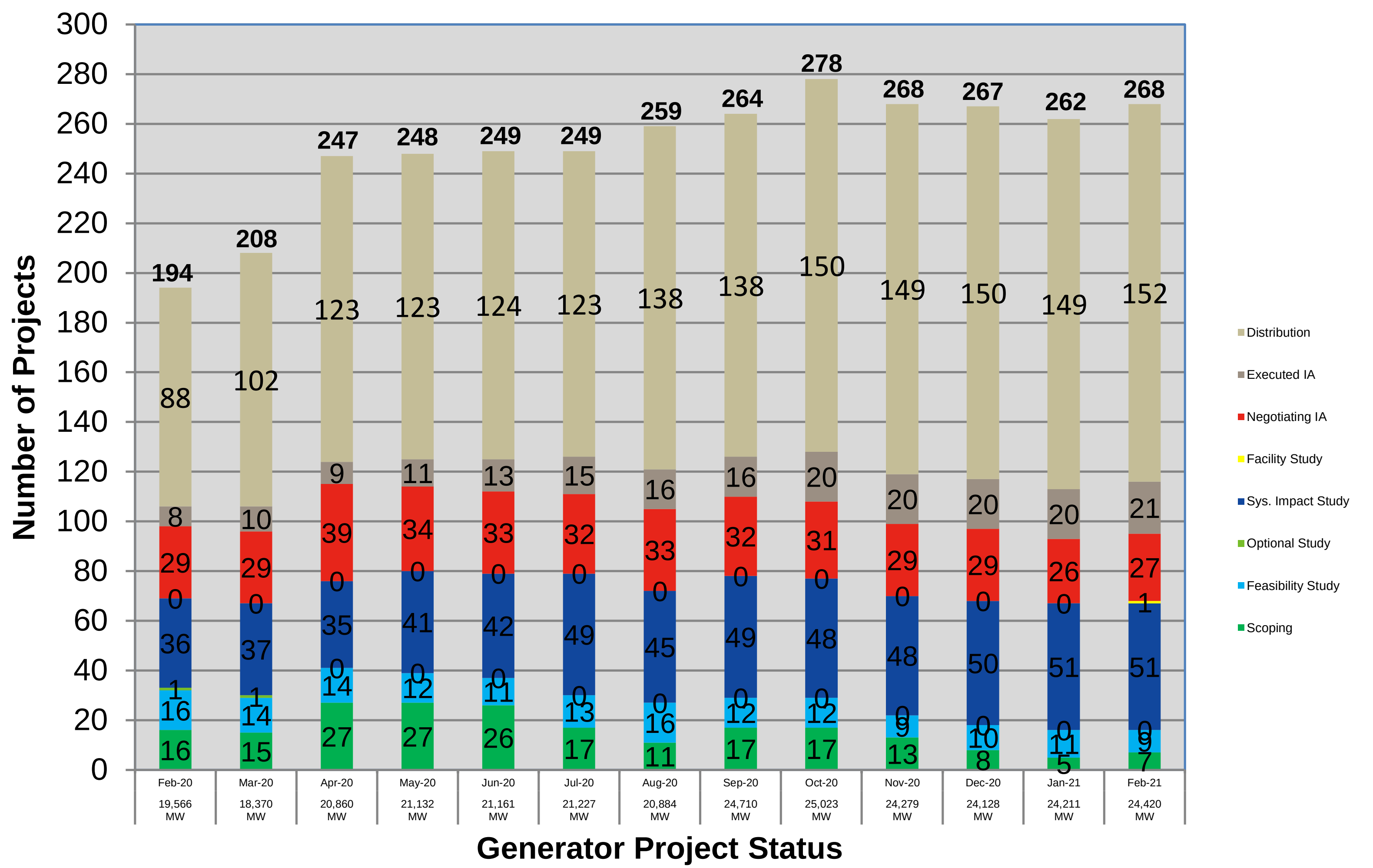
Eastern CT Reliability Projects, cont.

Status as of 2/19/2021

Project Benefit: Addresses system needs in the Eastern Connecticut area

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

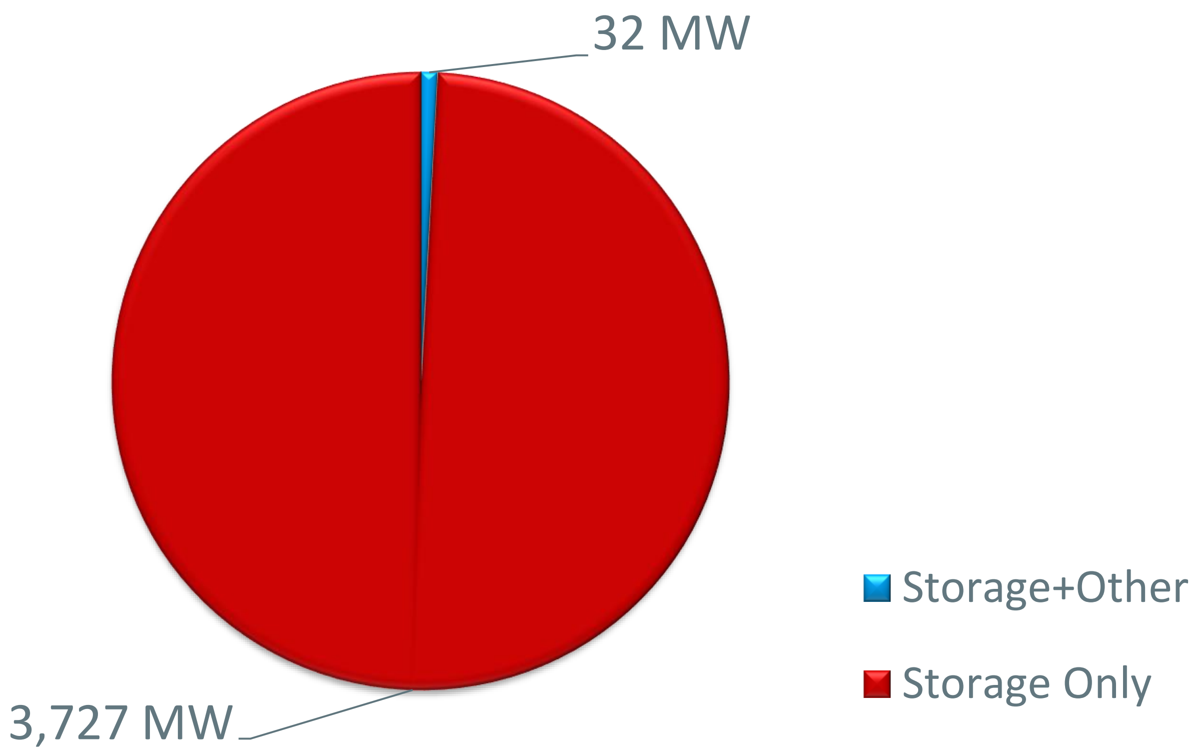
Status of Tariff Studies



Note: February 2021 is based on partial data.
As of February 2021, there are 0 ETU's in Scoping, 0 in FS, 3 in SIS, 0 in OIS, 0 in FAC, 0 Negotiating IA, and 2 with Executed IA.
https://irtt.iso-ne.com/external.aspx

What is in the Queue (as of February 24, 2021)

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



OPERABLE CAPACITY ANALYSIS

Winter 2021 Analysis

Winter 2021 Operable Capacity Analysis

50/50 Load Forecast (Reference)	March - 2021[2] CSO (MW)	March - 2021[2] SCC (MW)
Operable Capacity MW [1]	30,428	33,752
Active Demand Capacity Resource (+) [5]	425	410
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,119	1,119
Non Commercial Capacity (+)	7	7
Non Gas-fired Planned Outage MW (-)	2,216	2,400
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,200	2,200
Generation at Risk Due to Gas Supply (-) [3]	1,245	1,422
Net Capacity (NET OPCAP SUPPLY MW)	26,318	29,266
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	17,941	17,941
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	20,246	20,246
Operable Capacity Margin	6,072	9,020

[1]Operable Capacity is based on data as of **February 23, 2021** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **February 23, 2021.**

[2] Load forecast that is based on the 2020 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **March 6, 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.

Winter 2021 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	March - 2021[2] CSO (MW)	March - 2021[2] SCC (MW)
Operable Capacity MW [1]	30,428	33,752
Active Demand Capacity Resource (+) [5]	425	410
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,119	1,119
Non Commercial Capacity (+)	7	7
Non Gas-fired Planned Outage MW (-)	2,216	2,400
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,200	2,200
Generation at Risk Due to Gas Supply (-) [3]	2,179	2,489
Net Capacity (NET OPCAP SUPPLY MW)	25,384	28,199
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	18,520	18,520
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	20,825	20,825
Operable Capacity Margin	4,559	7,374

[1]Operable Capacity is based on data as of **February 23, 2021** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **February 23, 2021.**

[2] Load forecast that is based on the 2020 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **March 6, 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.

Winter 2021 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

February 26, 2021 - 50-50 FORECAST using CSO

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

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	Active Capacity Demand MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERATOR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
3/6/2021	**30428**	**425**	**1119**	**7**	**2216**	**0**	**2200**	**1245**	**26318**	**17941**	**2305**	**20246**	**6072**
3/13/2021	30428	425	1119	7	1850	250	2200	373	27306	17736	2305	20041	7265
3/20/2021	30428	425	1119	7	1874	1560	2200	0	26345	17352	2305	19657	6688
3/27/2021	30460	509	1025	7	790	244	2700	0	28267	16759	2305	19064	9203

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)

Winter 2021 Operable Capacity Analysis

90/10 Forecast (Extreme)

ISO-NE OPERABLE CAPACITY ANALYSIS

February 26, 2021 - 90-10 FORECAST using CSO

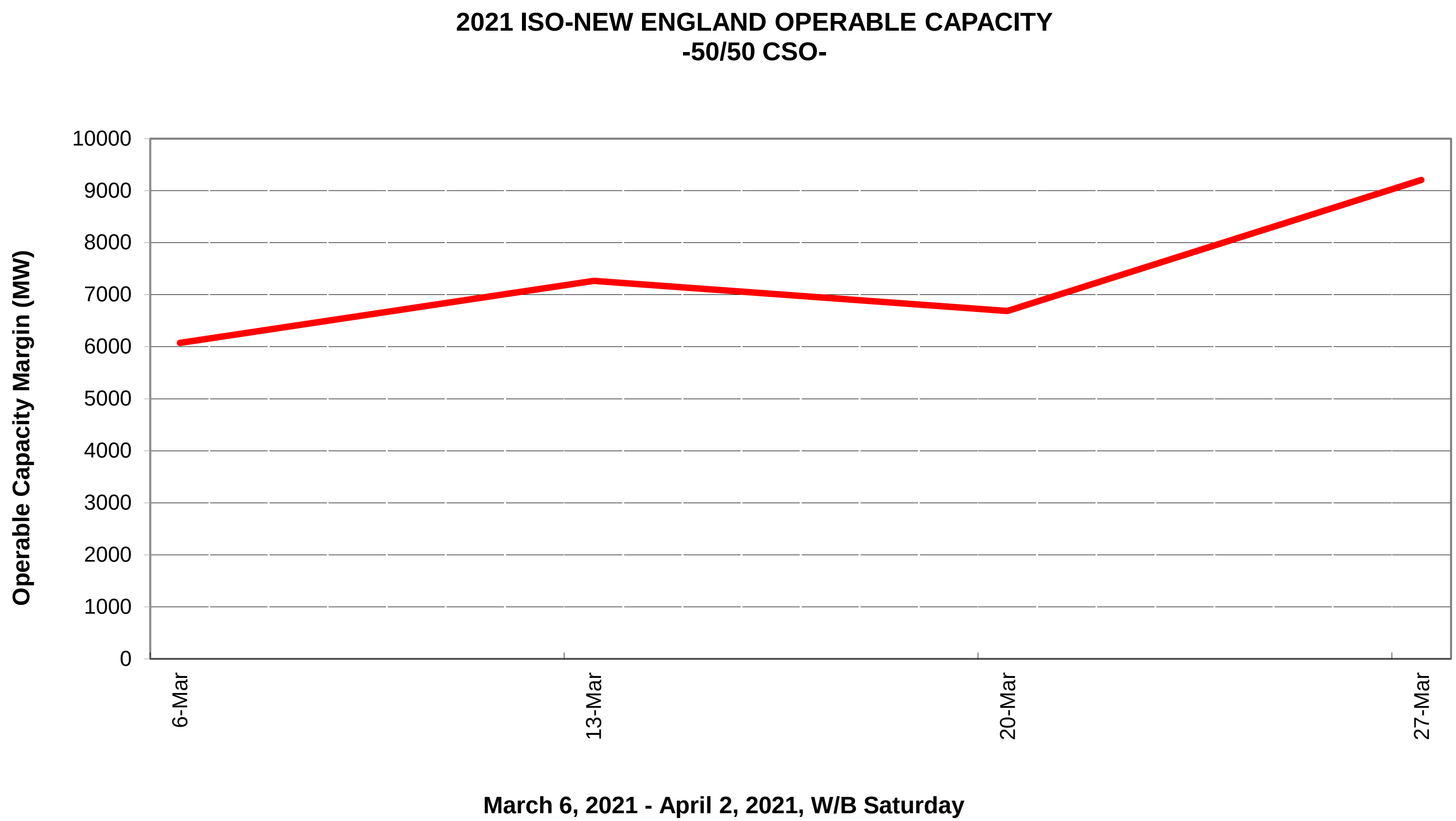
This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week during June, July, August, and Mid September

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]
3/6/2021	**30428**	**425**	**1119**	**7**	**2216**	**0**	**2200**	**2179**	**25384**	**18520**	**2305**	**20825**	**4559**
3/13/2021	30428	425	1119	7	1850	250	2200	1307	26372	18309	2305	20614	5758
3/20/2021	30428	425	1119	7	1874	1560	2200	0	26345	17915	2305	20220	6125
3/27/2021	30460	509	1025	7	790	244	2700	379	27888	17305	2305	19610	8278

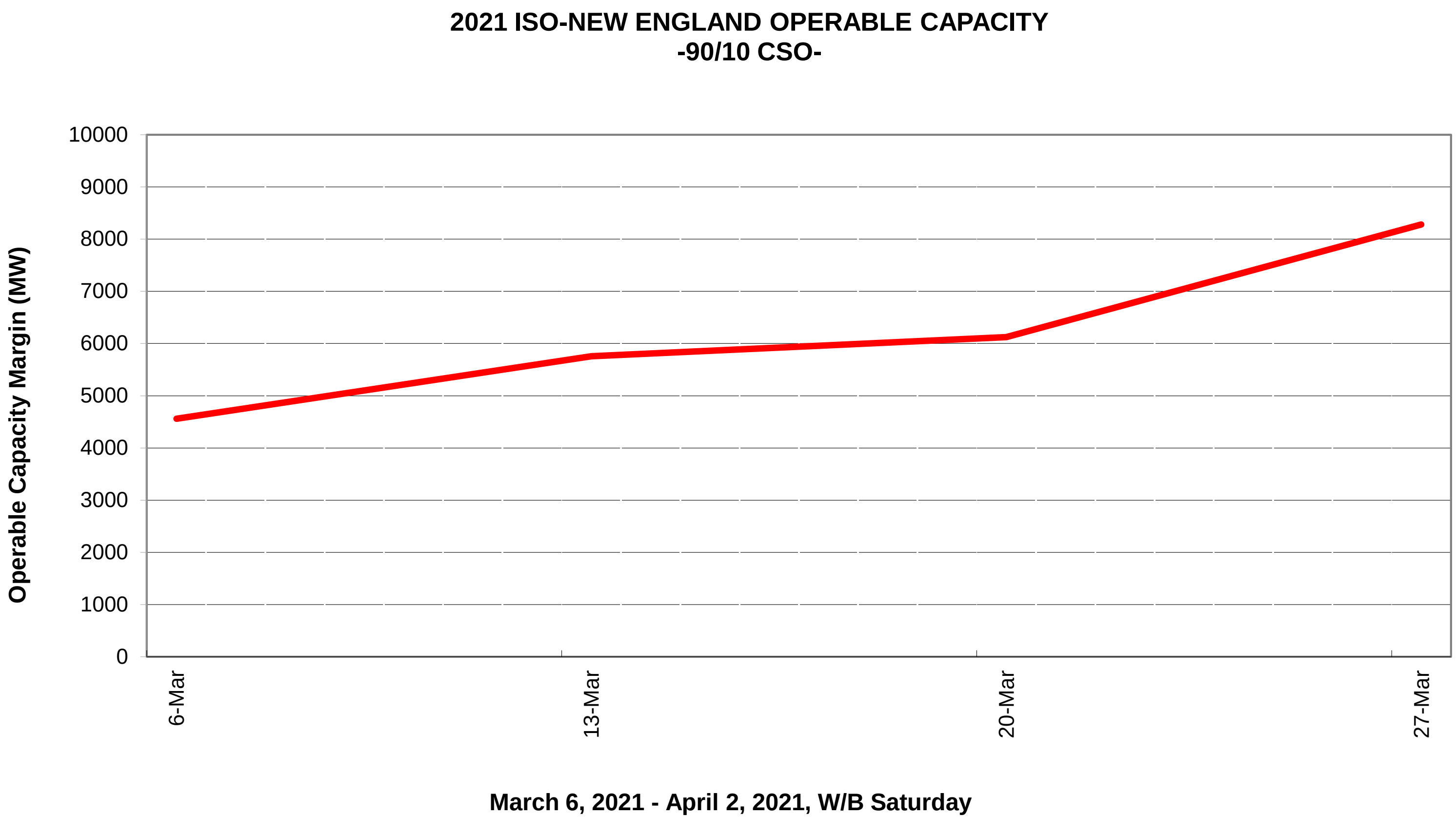
1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. The active demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity Market (FCM). 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 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**

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



Winter 2021 Operable Capacity Analysis
90/10 Forecast (Extreme)



OPERABLE CAPACITY ANALYSIS

Spring 2021 Analysis

Spring 2021 Operable Capacity Analysis

50/50 Load Forecast (Reference)	May - 2021[2] CSO (MW)	May - 2021[2] SCC (MW)
Operable Capacity MW [1]	30,448	33,752
Active Demand Capacity Resource (+) [5]	536	437
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,025	1,025
Non Commercial Capacity (+)	7	7
Non Gas-fired Planned Outage MW (-)	2,745	3,026
Gas Generator Outages MW (-)	2,433	2,705
Allowance for Unplanned Outages (-) [4]	3,400	3,400
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	23,438	26,090
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	18,118	18,118
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	20,423	20,423
Operable Capacity Margin	3,015	5,667

[1] Operable Capacity is based on data as of **February 23, 2021** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **February 23, 2021.**

[2] Load forecast that is based on the 2020 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 8, 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.

Spring 2021 Operable Capacity Analysis

90/10 **Load Forecast** (Extreme)	**May - 2021[2] CSO (MW)**	**May - 2021[2] SCC (MW)**
Operable Capacity MW [1]	30,448	33,752
Active Demand Capacity Resource (+) [5]	536	437
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,025	1,025
Non Commercial Capacity (+)	7	7
Non Gas-fired Planned Outage MW (-)	2,745	3,026
Gas Generator Outages MW (-)	2,433	2,705
Allowance for Unplanned Outages (-) [4]	3,400	3,400
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	23,438	26,090
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	19,612	19,612
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	21,917	21,917
Operable Capacity Margin	1,521	4,173

[1]Operable Capacity is based on data as of **February 23, 2021** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **February 23, 2021.**

[2] Load forecast that is based on the 2020 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 8, 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.

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

ISO-NE OPERABLE CAPACITY ANALYSIS

February 26, 2021 - 50-50 FORECAST using CSO

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

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	Active Capacity Demand MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERATOR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
4/3/2021	30460	509	1025	7	3929	1641	2700	0	23731	16134	2305	18439	5292
4/10/2021	30460	509	1025	7	5506	1850	2700	0	21945	15870	2305	18175	3770
4/17/2021	30460	509	1025	7	5481	1342	2700	0	22478	15335	2305	17640	4838
4/24/2021	30460	509	1025	7	3245	1770	2700	0	24286	15057	2305	17362	6924
5/1/2021	30448	536	1025	7	3096	1983	3400	0	23537	15029	2305	17334	6203
5/8/2021	**30448**	**536**	**1025**	**7**	**2745**	**2433**	**3400**	**0**	**23438**	**18118**	**2305**	**20423**	**3015**
5/15/2021	30448	536	1025	7	1460	1812	3400	0	25344	19152	2305	21457	3887
5/22/2021	30448	536	1025	7	1273	1213	3400	0	26130	20113	2305	22418	3712

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)

Spring 2021 Operable Capacity Analysis

90/10 Forecast (Extreme)

ISO-NE OPERABLE CAPACITY ANALYSIS

February 26, 2021 - 90-10 FORECAST using CSO

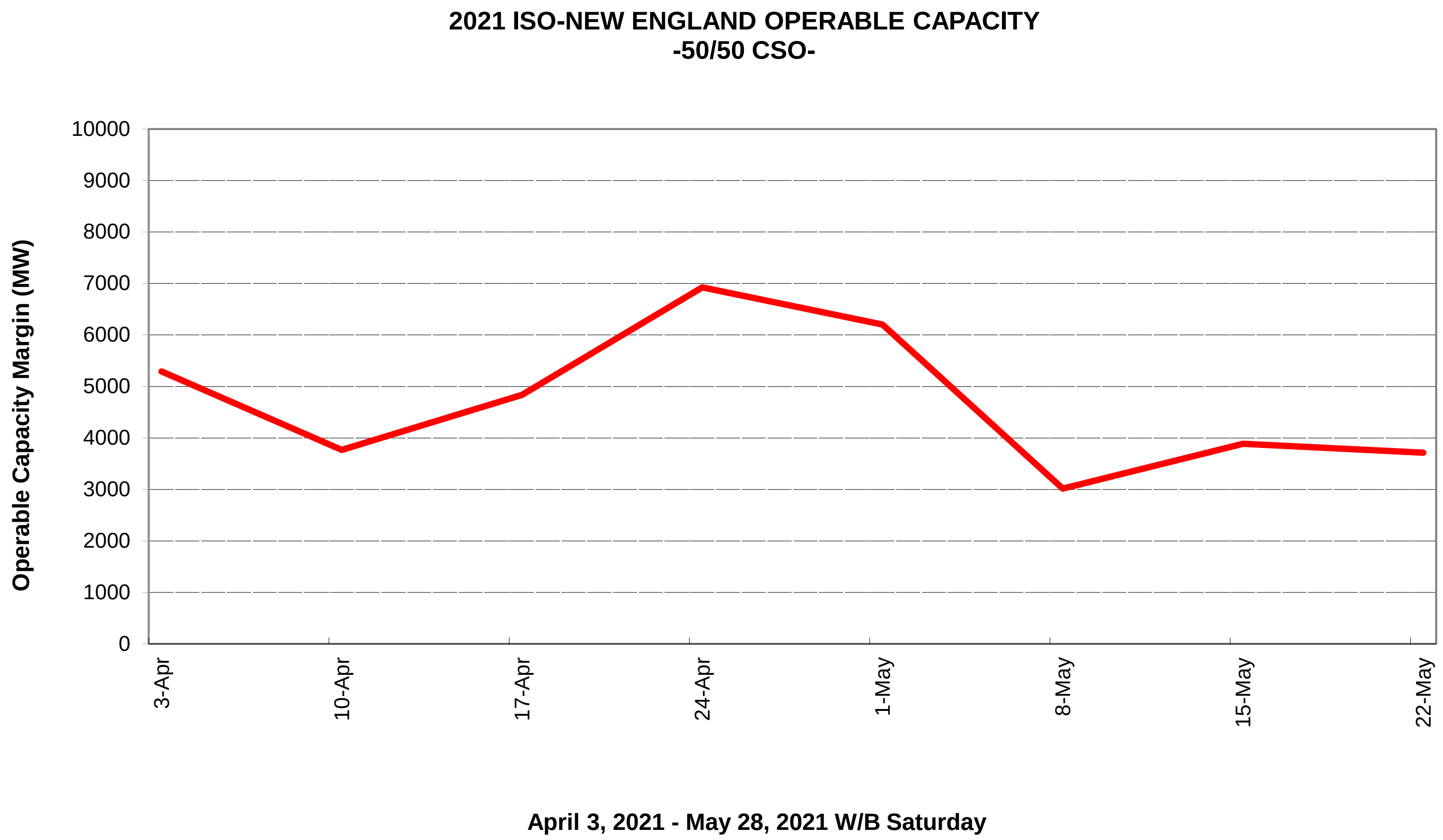
This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week during June, July, August, and Mid September

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	Active Capacity Demand MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERATOR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
4/3/2021	30460	509	1025	7	3929	1641	2700	0	23731	16667	2305	18972	4759
4/10/2021	30460	509	1025	7	5506	1850	2700	0	21945	16395	2305	18700	3245
4/17/2021	30460	509	1025	7	5481	1342	2700	0	22478	15846	2305	18151	4327
4/24/2021	30460	509	1025	7	3245	1770	2700	0	24286	15560	2305	17865	6421
5/1/2021	30448	536	1025	7	3096	1983	3400	0	23537	15531	2305	17836	5701
5/8/2021	**30448**	**536**	**1025**	**7**	**2745**	**2433**	**3400**	**0**	**23438**	**19612**	**2305**	**21917**	**1521**
5/15/2021	30448	536	1025	7	1460	1812	3400	0	25344	20716	2305	23021	2323
5/22/2021	30448	536	1025	7	1273	1213	3400	0	26130	21741	2305	24046	2084

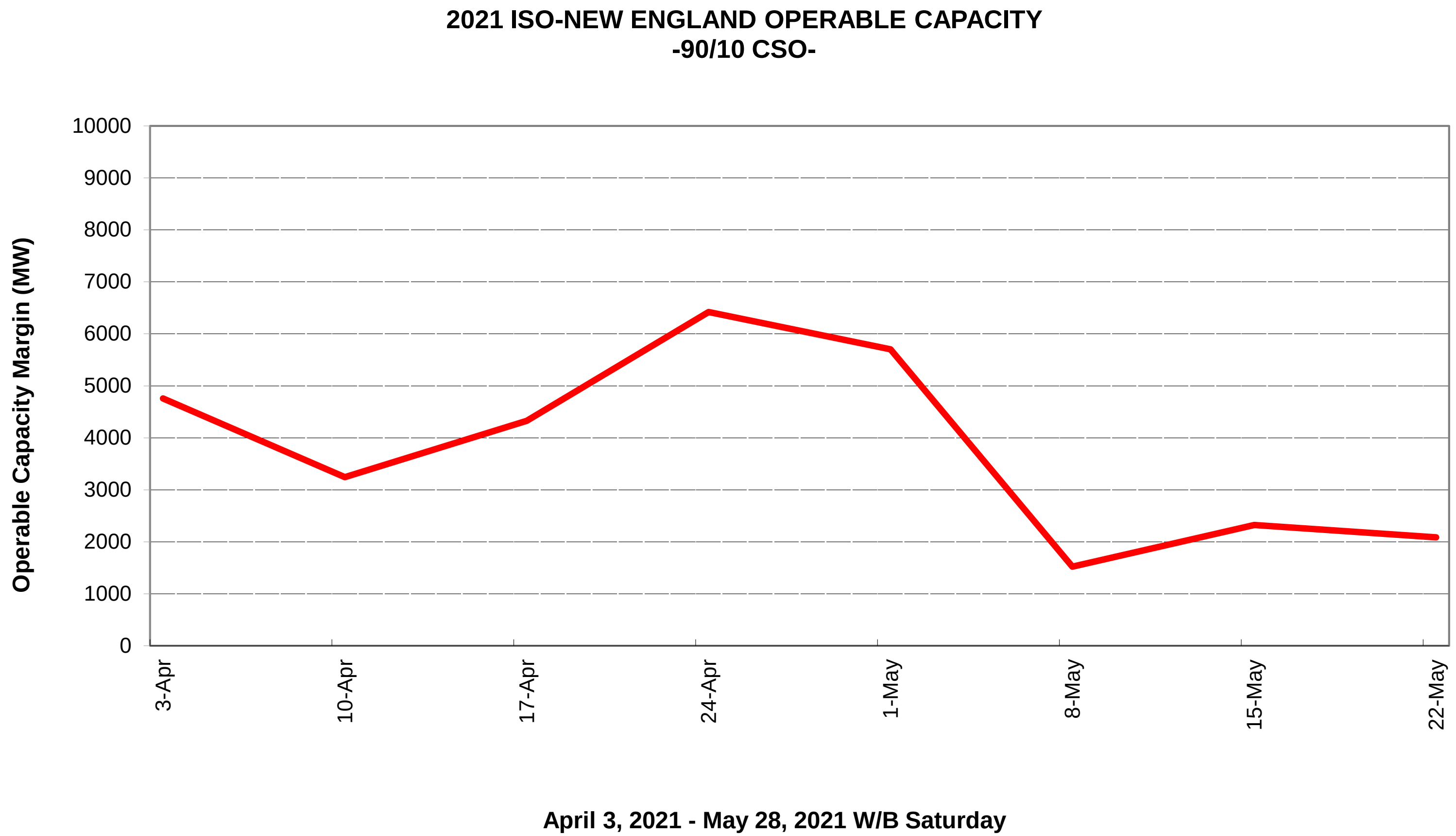
1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. The active demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity Market (FCM). 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 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**

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



Spring 2021 Operable Capacity Analysis
90/10 Forecast (Extreme)



OPERABLE CAPACITY ANALYSIS

Appendix

Possible Relief Under OP4: Appendix A

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

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

Possible Relief Under OP4: Appendix A

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

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

Review of February 2021 Extreme Cold Weather Event – ERCOT Presentation

Bill Magness
President & Chief Executive Officer
ERCOT

Urgent Board of Directors Meeting

ERCOT Public
February 24, 2021

Disclaimer

Information in this presentation is preliminary and represents the best available data at the time it was created.

ERCOT Corporate Governance

- **Founded in 1970**
- **Texas non-profit corporation with members from seven market segments:**
  - Consumers (Commercial, Industrial, Residential)
  - Cooperatives
  - Independent Generators
  - Independent Power Marketers
  - Independent Retail Electric Providers
  - Investor-Owned Utilities
  - Municipals
- **The Texas Legislature enacted laws which govern all activities of ERCOT – See Public Utility Regulatory Act (PURA) Section 39.151.**
- **The Public Utility Commission of Texas (PUC) has complete authority over ERCOT's finances, budget and operations, with oversight by the Texas Legislature.**
  - Approves ERCOT Bylaws
- **16-member ERCOT Board composition is established by law:**
  - 5 Unaffiliated Directors (independent from ERCOT Market Participants); all must be approved by the PUC for three-year terms with a maximum of two renewals
  - 8 Directors each elected annually by different Market Segments
  - Office of Public Utility Counsel (represents Residential Consumer Market Segment)
  - ERCOT Chief Executive Officer
  - PUC Chairman (non-voting)

ERCOT's Role

- **Fulfills four responsibilities required by law as the independent organization certified by the PUC (PURA Section 39.151):**
  - Maintain electric system reliability
  - Facilitate a competitive wholesale market
  - Ensure open access to transmission
  - Facilitate a competitive retail market
- **Manages the flow of electric power over the bulk power system to approximately 26 million Texas end-use customers.**
  - About 90% of the state's electric load
  - Over 680 generation units
  - Over 46,500 miles of transmission lines
- **Must, at all times (24/7/365), balance all consumer demand in the ERCOT region (load) and the power supplied by companies who generate electricity (generation) while maintaining system frequency of 60 Hz.**
- **Performs financial settlement for the competitive wholesale bulk power market and administers retail switching for nearly 8 million premises in competitive choice areas.**

ERCOT's Role (continued)

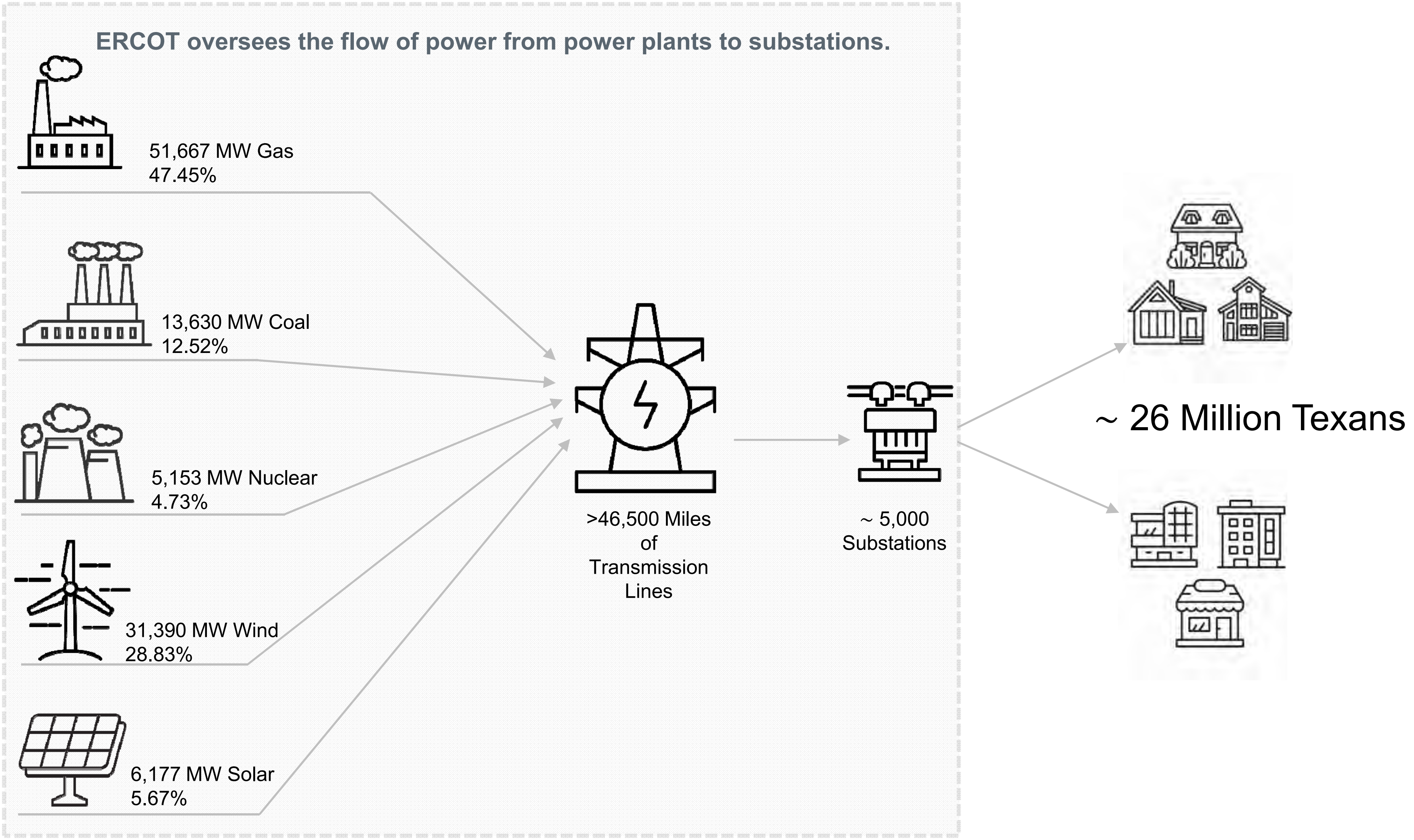
ERCOT does **not**:

- Own, operate or have any enforcement authority over any electric generation facilities or any electric transmission or distribution lines or substations.
- Sell or send bills for retail electricity to residences or businesses.
- Control or operate electric service to local areas, neighborhoods or individual premises.
- Establish pricing or rates for retail electric customers.
- Have any direct customer relationships with the public.

ERCOT Budget & Funding

- **Budget is approved by the Board and the PUC biennially.**
- **Funded by a System Administration Fee to cover its system costs.**
  - Current fee is 55.5 cents per megawatt hour (MWh).
  - One megawatt of electricity can power about 200 Texas homes during periods of peak demand.
  - Average cost of $7/year (50-60 cents/month) for residential households.
- **ERCOT does <u>not</u> set consumer electric rates.**
  - Rates are either set by the PUC or companies that sell electricity at retail to end-use customers.
  - Additional transmission costs are proportionally passed on to customers.

Electric Generation, Transmission & Distribution Overview



MW represent installed capacity

Pre-Event Operational Preparation

- Canceled transmission maintenance outages affecting over 1,600 transmission devices and delayed other outages.
- Reviewed planned generation outages for potential early return to service.
- Noted potential for 11,100 MW of forced outages due to gas restrictions based on gas company communications – more units affected during this event compared to previous cold weather events.
- Began using maximum icing potential for wind forecasts.
- Waived COVID restrictions and brought additional support staff on-site.
- Prepared facilities for extended on-site staffing, activated additional remote engineering/support staff.
- Began regular calls with Chief System Operators (18 over 8 days).
- Requested TCEQ/DOE enforcement discretion for power plant emissions during anticipated event.
- Supported Railroad Commission of Texas review of natural gas priority.

All available generation was online on February 14.

Pre-Event Communications

November 5	ERCOT meteorologist issues winter outlook for Market Participants and public noting the "very good" chance for an extreme cold weather event during winter 2020/2021.
February 3	ERCOT meteorologist warns Market Participants and the public of coldest weather of the year. Weather updates continue.
February 8	Operating Condition Notice issued for extreme cold weather event, posted on public website.
February 10	Advisory issued for extreme cold weather event posted on public website. Issued grid conditions update for market media representatives.
February 11	Watch issued for cold weather event (hotline calls made, notice to Market Participants, posted on public website). News release on extreme weather expected, social media outreach.
February 12	Texas Energy Reliability Council meeting.
February 13	State Operations Center news conference: forecast Conservation Alert. Emergency notice issued for extreme cold weather event, posted on public website. Texas Energy Reliability Council meeting.
February 14	Issued conservation appeal by news release, performed social media outreach, held media briefing.

Overview of Cold Weather Event

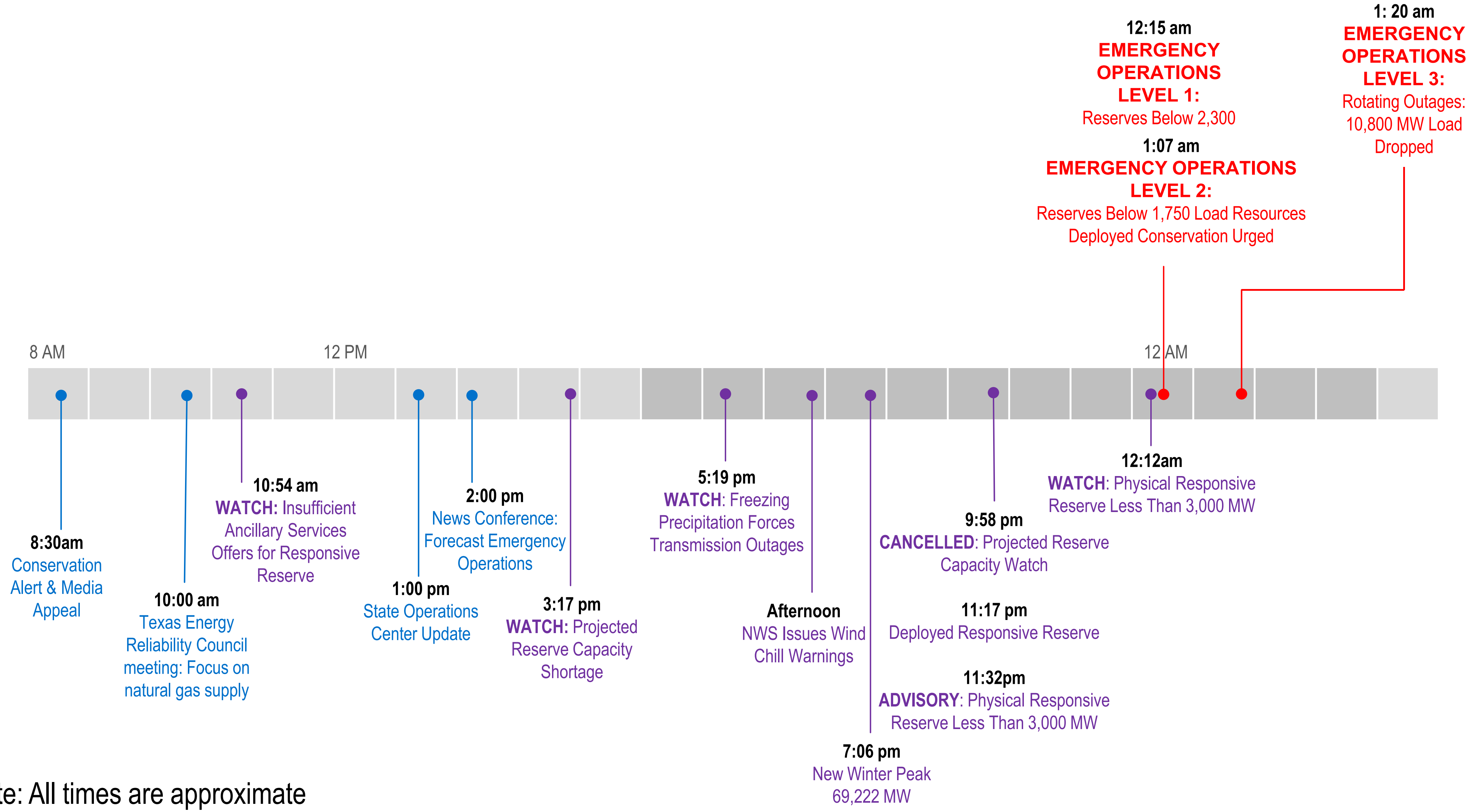
- Record-setting, sub-freezing temperatures and wind chills across the state.

- Approximately 48.6% of generation was forced out at the highest point due to the impacts of various extreme weather conditions.

- Controlled outages were implemented to prevent statewide blackout.
  - Electric demand had to be limited to available generation supply.

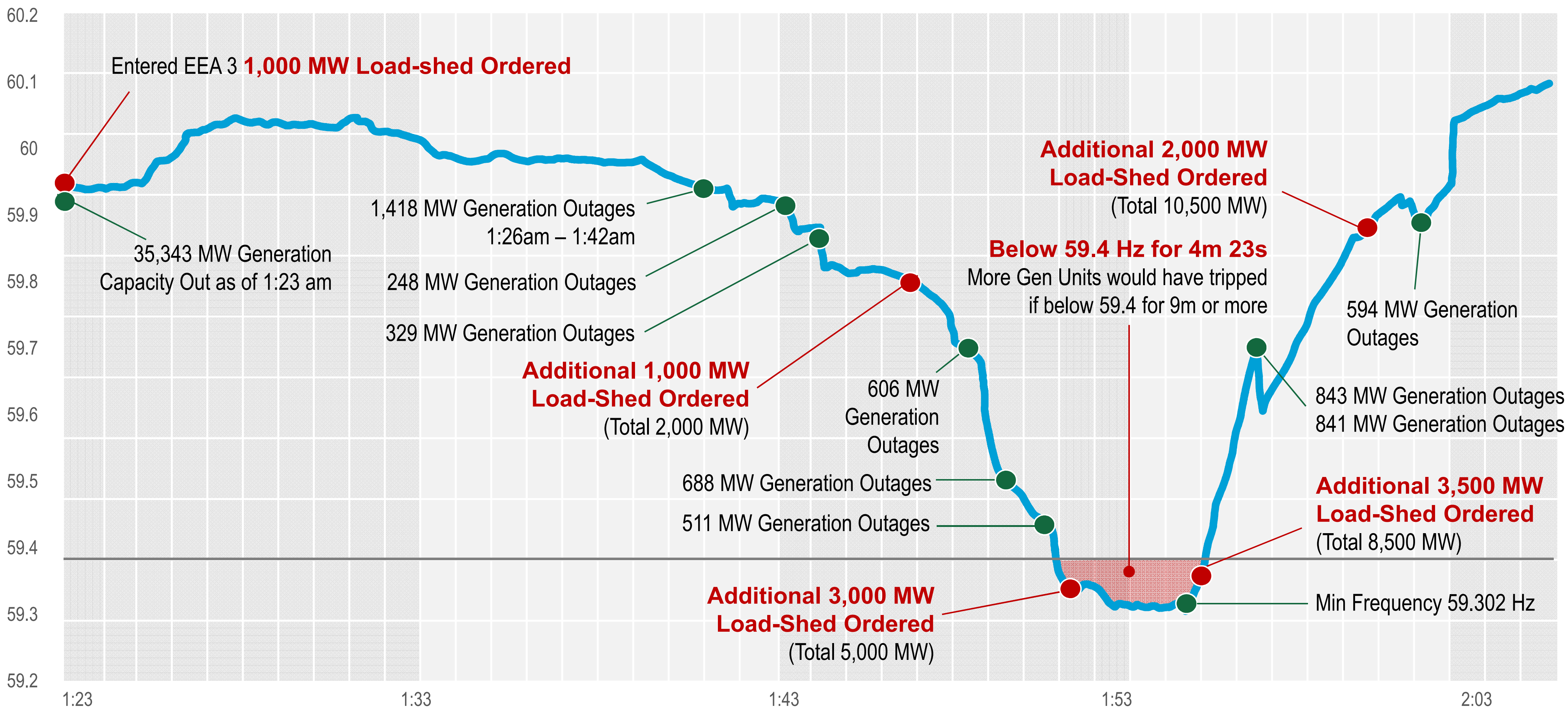
- Local utilities were limited in their ability to rotate outages due to the magnitude of generation unavailability and the number of circuits with critical load.

Sunday, February 14 – Monday, February 15

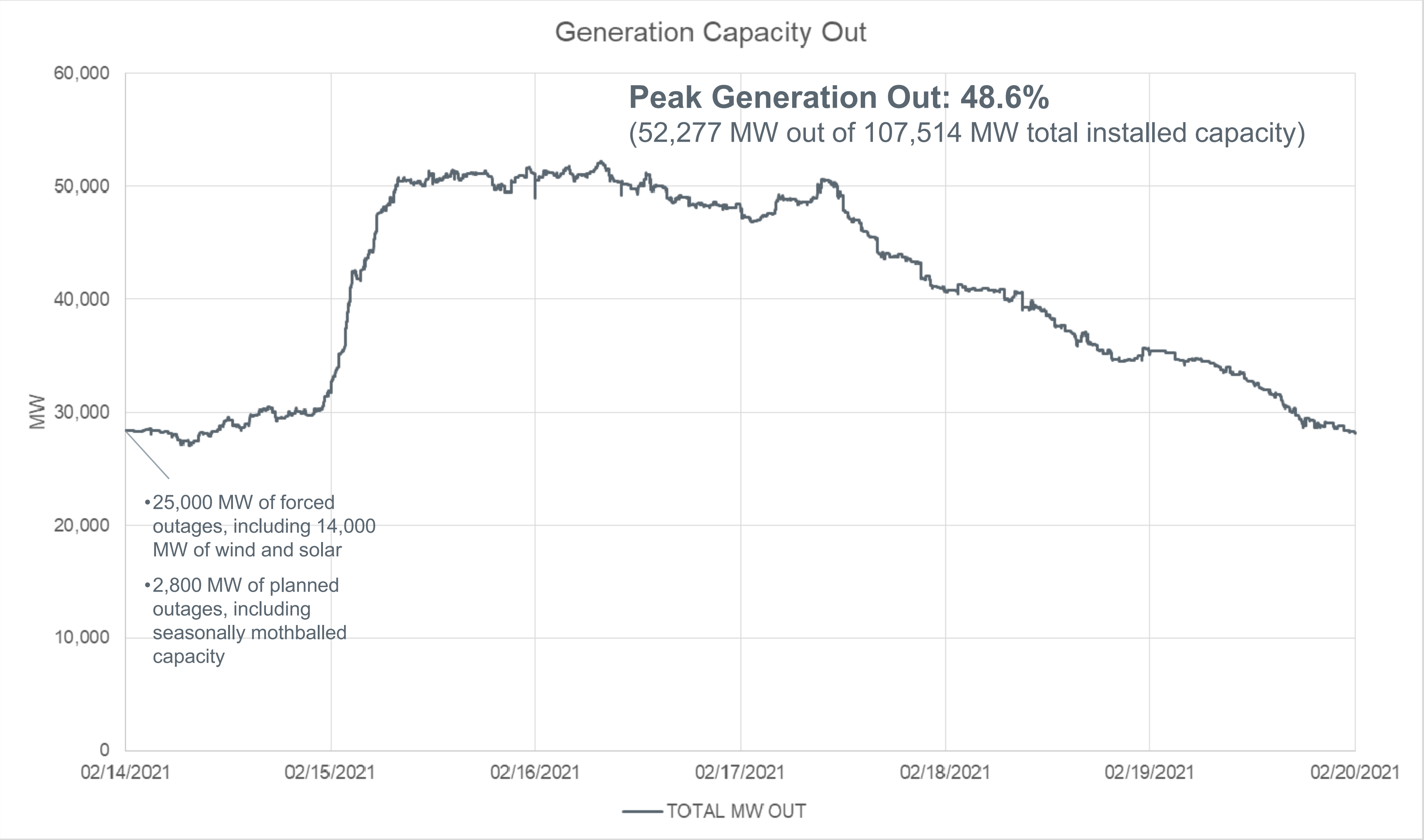


Note: All times are approximate

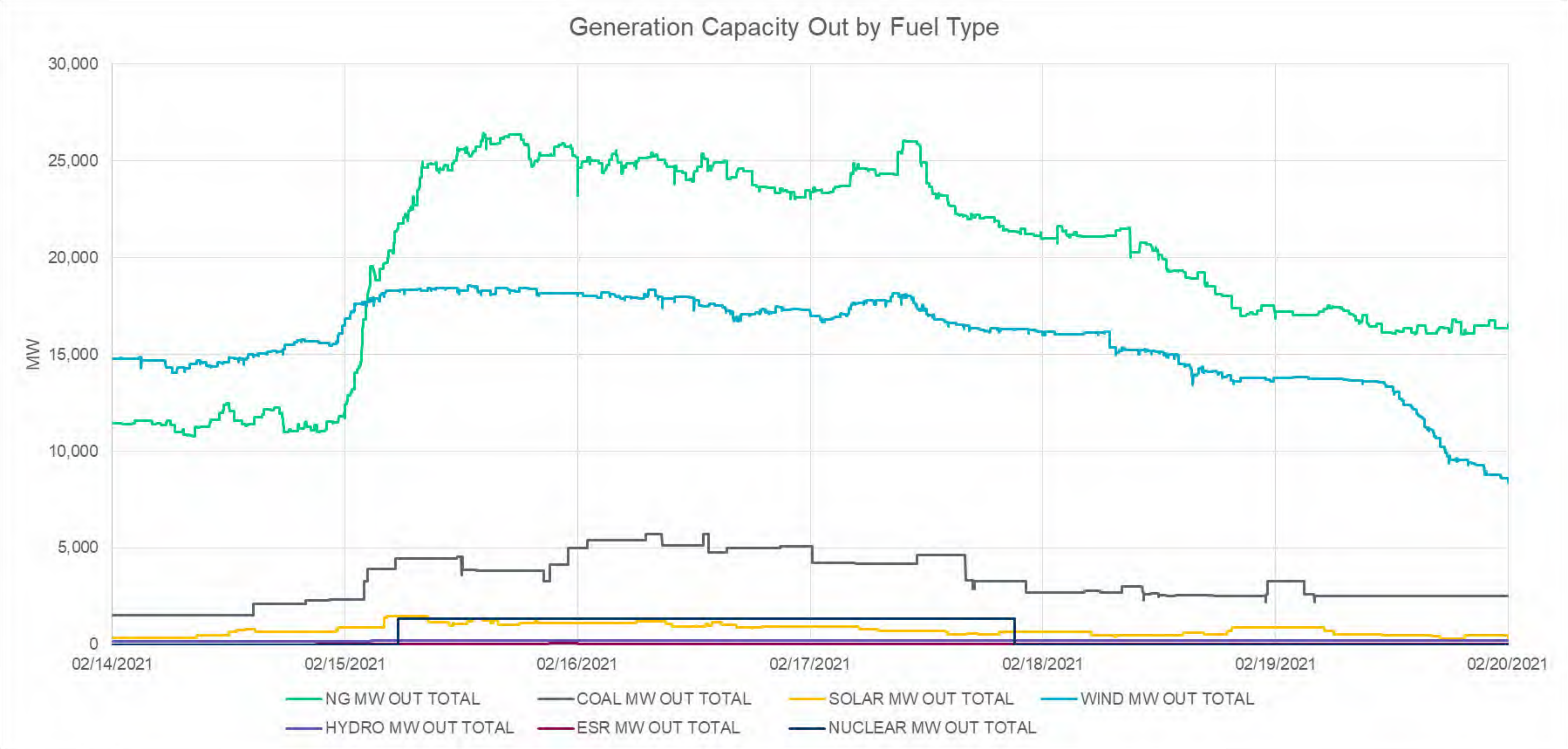
Rapid Decrease in Generation Causes Frequency Drop



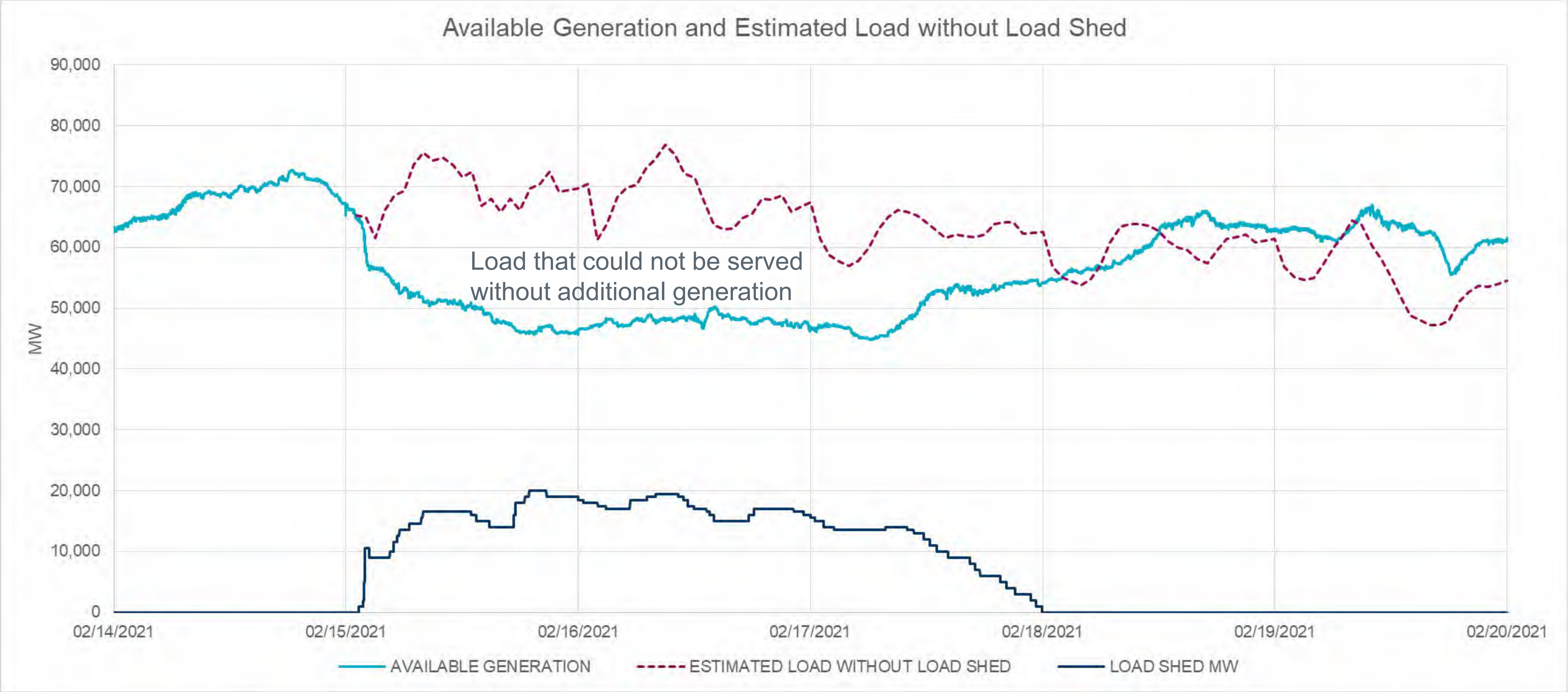
Generation Capacity Out February 14 – 19, 2021



Generation Capacity Out by Fuel Type



Available Generation and Estimated Load Without Load Shed



Available Generation shown is the total HSL of Online Resources, including Quick Starts in OFFQS. The total uses the current MW for Resources in Start-up, Shut-Down, and ONTEST.

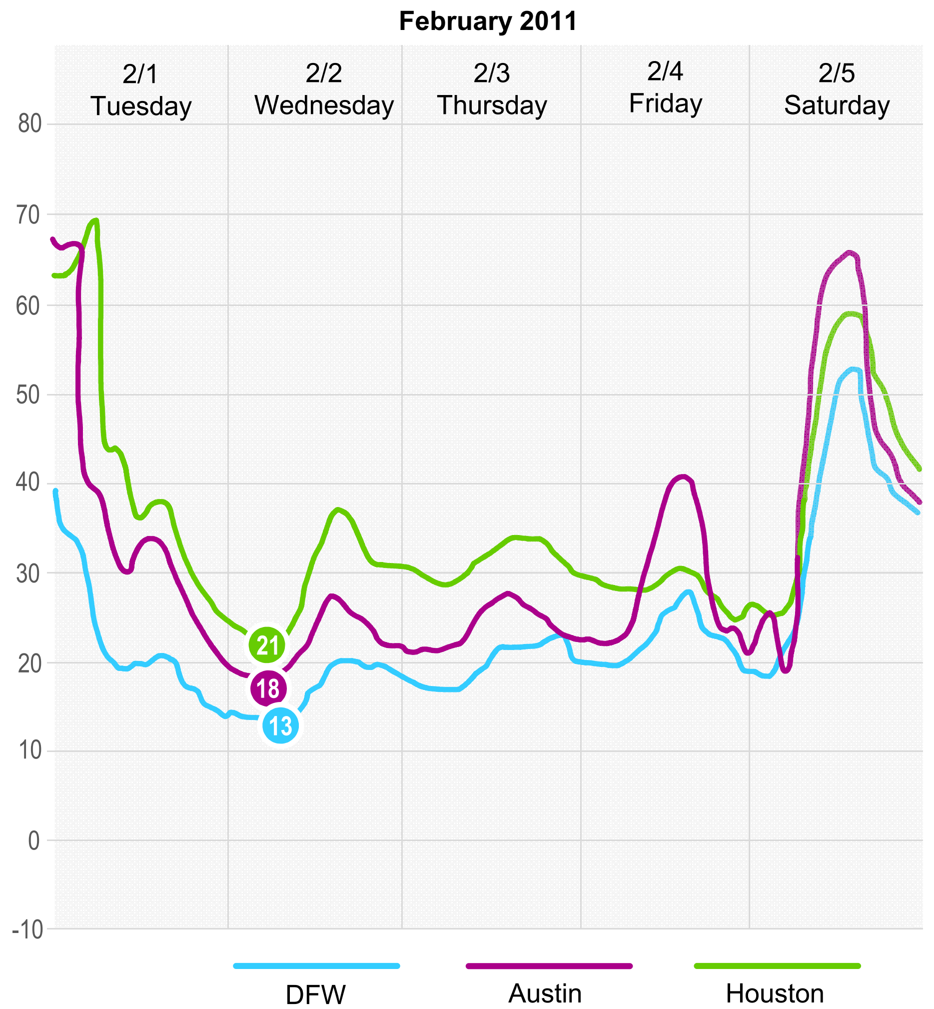
Key Events (Monday, February 15 – Friday, February 19)

- More than 16,500 control room calls with generators and transmission owners (normal: ~5,000/week).
- Multiple daily coordinating calls between transmission owners and operations management.
- Monday, February 15
  - Up to an additional ~24,000 MW net generation unavailable due to extreme weather; loss of generation was 52,277 MW (approximately 48.6%) at the highest point.
  - 20,000 MW peak load shed.
  - Limited gas availability for gas-fired power plants.
  - Multiple DC-Tie constraints due to neighboring area emergencies.
  - Daily Texas Energy Reliability Council meetings.
- Tuesday, February 16
  - No net gain in generation as some generators were restored and others became unavailable.
  - Decreased volume of controlled outages during the day, increased for evening peak.
- Wednesday, February 17
  - Moderating temperatures allowed reduction in controlled outages, small net gain in generation.
- Thursday, February 18
  - Continued gain in generation.
  - 12:42 a.m. - Canceled last controlled outage orders - some outages remained due to ice storm damage; need for manual restoration and return of large industrial facilities.
- Friday, February 19 (all times approximate)
  - 9 a.m. - Returned to emergency operations level 2
  - 10 a.m. – Returned to emergency operations level 1
  - 10:35 a.m. – Returned to normal operations

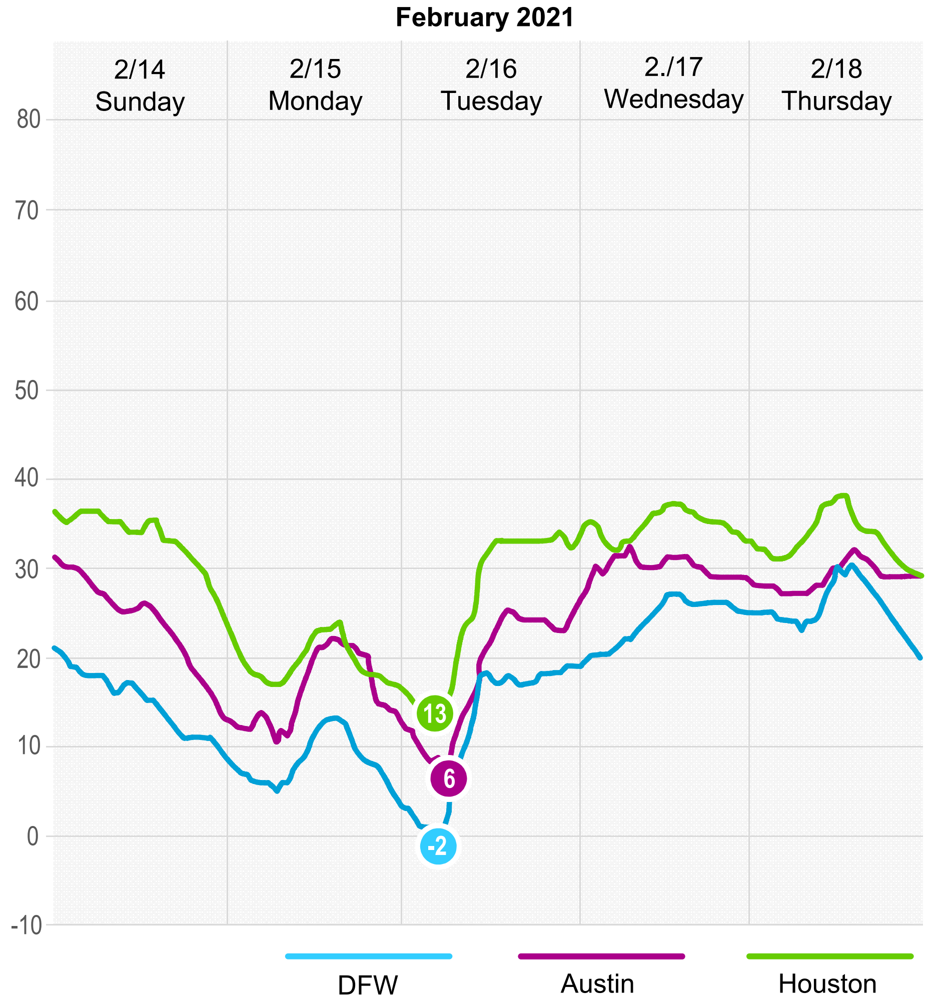
Generation Weatherization

- Generation owners and operators are not required to implement any minimum weatherization standard or perform an exhaustive review of cold weather vulnerability. No entity, including the PUC or ERCOT, has rules to enforce compliance with weatherization plans or enforce minimum weatherization standards.
- In 2011, the PUC amended its rules to authorize ERCOT to conduct generator site visits to review compliance with weatherization plans. Spot checks include reviewing the weatherization plan, verifying that plant personnel are following the plan and providing recommendations based on PUC requirements, lessons learned or best practices.
- We currently perform spot checks at power plant units at the rate of about 80/year. Whenever possible, a Texas Reliability Entity (TRE) representative joins ERCOT for these spot checks.
- While we request and review detailed plant records, the only entity that can confirm that a plant is “weatherized” to any particular standard is the entity that owns or operates the plant.
- Each year, TRE and ERCOT host an annual workshop on weatherization with generation owners to review lessons learned and best practices.

2011 vs. 2021 Event Temperature Comparison



Consecutive Hours at or below freezing — DFW 101 — Austin 69 — Houston 34



Consecutive Hours at or below freezing — DFW 140 — Austin 162 — Houston 44

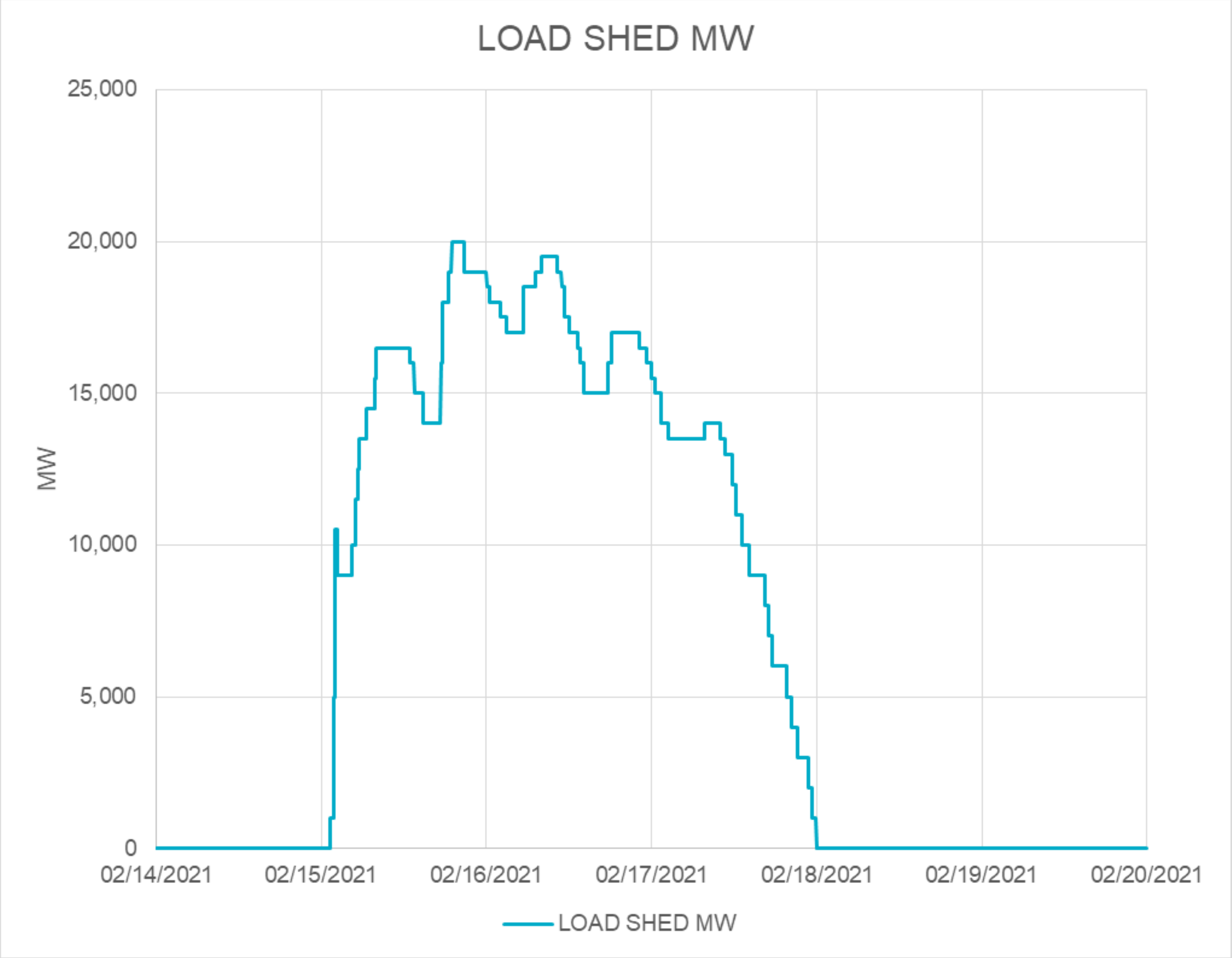
2011 vs. 2021 Event Comparison

	2011	2021
Maximum generation capacity forced out at any given time (MW)	14,702	52,277
Generation forced out one hour before start of EEA3 (MW)	1,182	2,489
Cumulative generation capacity forced out throughout the event (MW)	29,729	46,249*
Cumulative number of generators outaged throughout the event	193	356
Cumulative gas generation de-rated due to supply issues	1,282	9,323
Lowest frequency	59.58	59.30
Maximum load shed requested (MW)	4,000	20,000
Duration load shed request (hours)	7.5	70.5
Estimated peak load (without load shed)	59,000	76,819

*Note: “Cumulative” values for 2021 were calculated using NERC 2011 report methodology.
Cumulative amount for 2021 starts at 00:01 on February 14, 2021

Load Shed Ordered By Transmission Owner

Transmission Operator	% of MW
AEP Texas Central Company	8.7
Brazos Electric Power Cooperative Inc.	4.95
Brownsville Public Utilities Board	0.37
Bryan Texas Utilities	0.51
CenterPoint Energy Houston Electric LLC	24.83
City of Austin DBA Austin Energy	3.71
City of College Station	0.28
City of Garland	0.75
CPS Energy (San Antonio)	6.79
Denton Municipal Electric	0.48
GEUS (Greenville)	0.15
Lamar County Electric Cooperative Inc*	0.07
LCRA Transmission Services Corporation	5.96
Oncor Electric Delivery Company LLC	36.01
Rayburn Country Electric Cooperative Inc.	1.3
South Texas Electric Cooperative Inc.	2.52
Texas-New Mexico Power Company	2.62
ERCOT Total	**100.00**



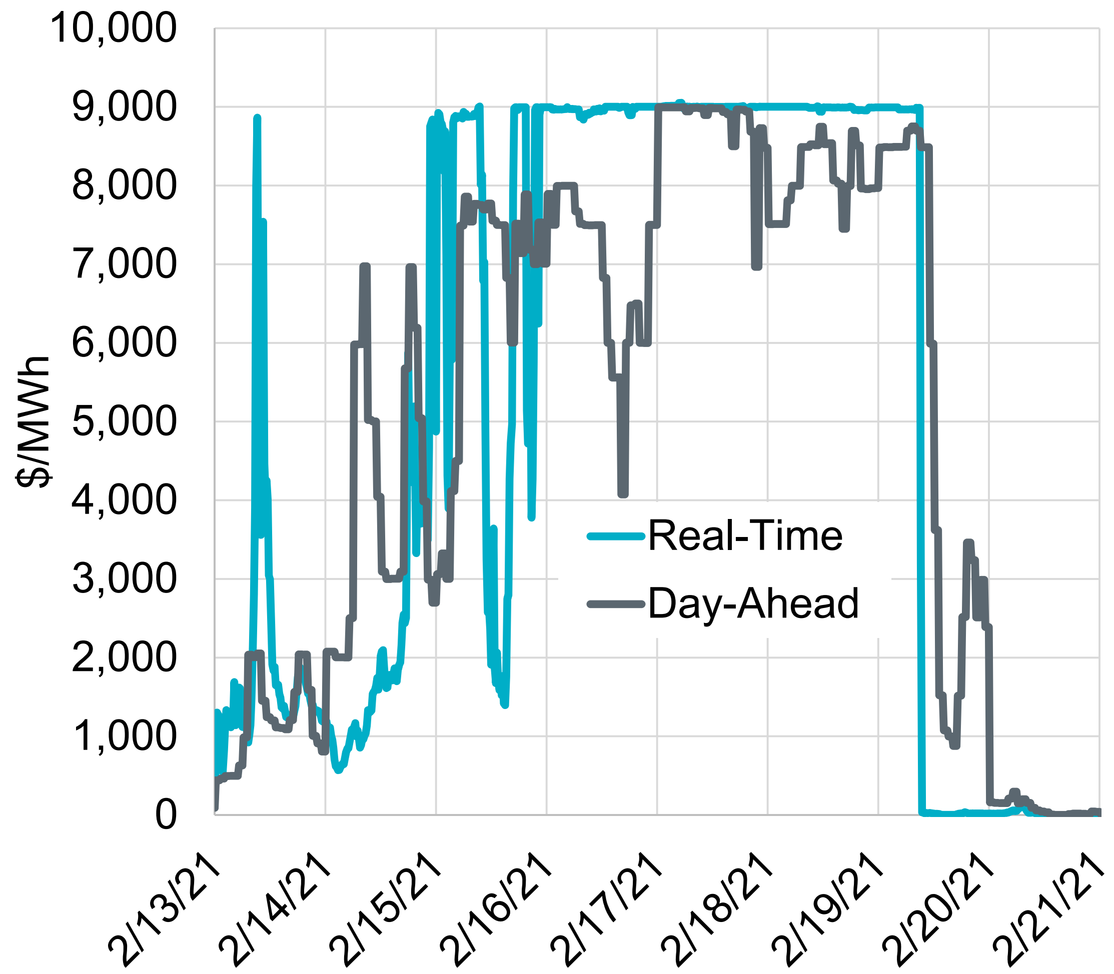
Status of Recommendations After February 2011

A report published by the North American Electric Reliability Corporation following the February 2011 cold weather event contained several recommendations applicable to ERCOT. Over the past 10 years, ERCOT has made changes that support those recommendations.

Significant modifications include:

- Implemented the Seasonal Assessment of Resource Adequacy report that includes an analysis for extreme winter weather.
- Began a resource weatherization process that includes an annual workshop, review of resource weatherization plans and spot checks of facilities.
- Added additional staff (Shift Engineer and Resource Reliability Desk) in the control room.
- Modified the Ancillary Services procurement to allow additional procurement in anticipation of severe weather.
- Established the Gas Electric Working Group and created a notification procedure for QSEs to notify ERCOT if there are anticipated fuel restrictions.
- Modified the survey sent to natural gas generators that collects fuel switching capability for some resources in preparation for each winter season.
- Changed the rules and processes for withdrawing approval of resource outages in anticipation of severe weather.

Real-Time and Day-Ahead System-Wide Pricing



Average system-wide pricing around the event relative to other historical periods (in $/MWh)

Date Range	Real-Time	Day-Ahead
2/14/21 2/19/21	$6,579.59	$6,612.23
January '21	$20.79	$21.36
February '20	$18.27	$17.74

This data is using the ERCOT Hub Average 345-kV Hub prices

Hedging by Market Participants

- ERCOT has limited visibility into other methods of hedging that Market Participants may engage in, including but not limited to commodities exchanges and bilateral contracts.

- With the information available to ERCOT, the level of energy hedging by Load Serving Entities varied from fairly long to fairly short relative to their physical load. This could also vary by operating day for the same entity.

- These positions would have been affected by load reductions resulting from the instructed firm load shed and other losses of load, as well as loss of generation through de-ratings or outages that occurred during the event.

Item 2.3: Market Financial Matters

Carrie Bivens
ERCOT IMM Director
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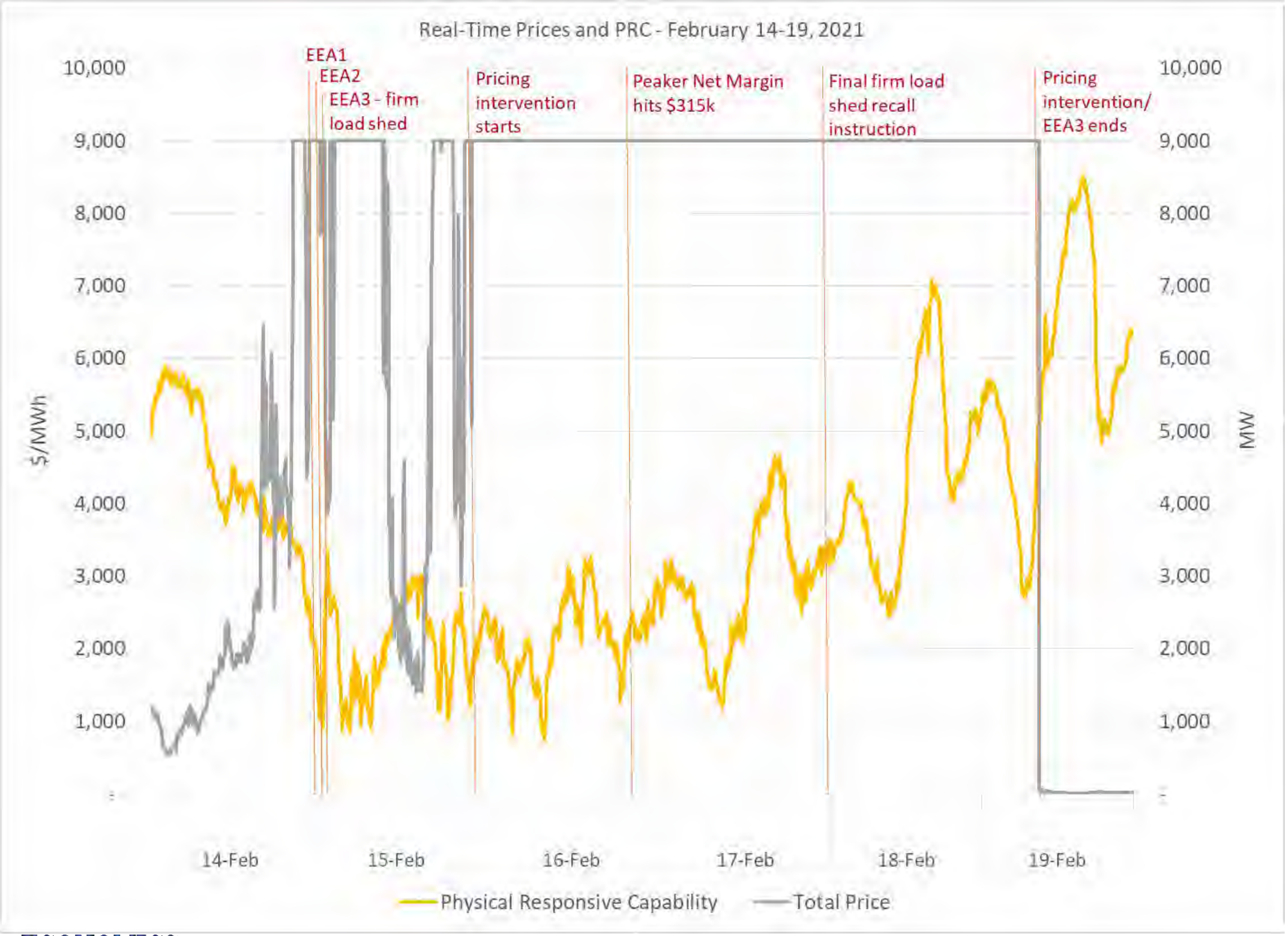
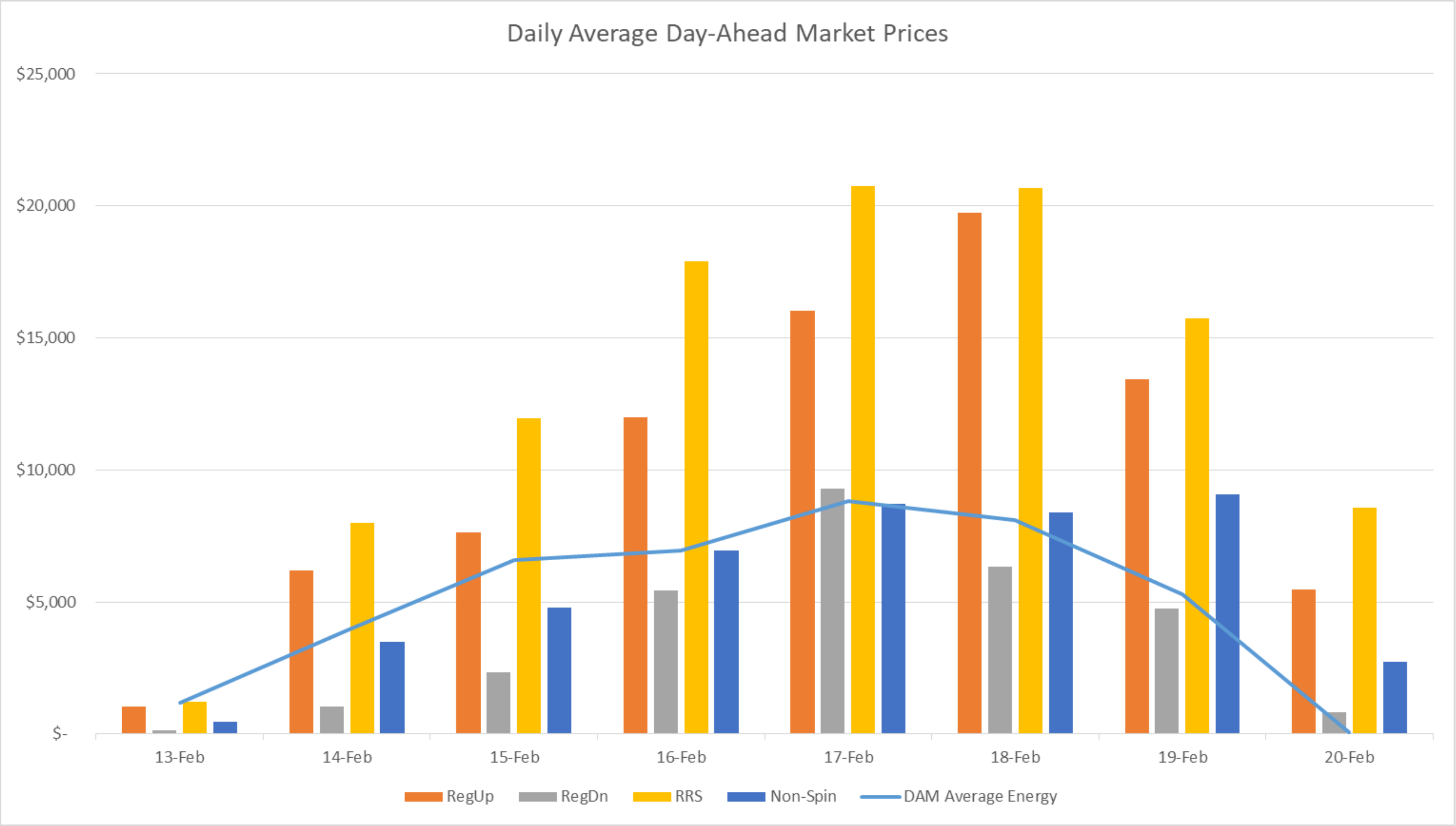
Urgent Board of Directors Meeting

ERCOT Public
February 24, 2021

Real-Time Energy Prices



Day-Ahead Prices



POTOMAC ECONOMICS

Overview of the ISO New England Board Search Process

March 2021

Overview: Our Search Process in Partnership with the ISO New England JNC

Assess needs

Board Analysis & Needs Assessment

- Diligence ISO New England's strategy over the next 3-5 years
- Conduct Board Composition Analysis exercise to assess current state of Board composition and identify key needs on the horizon. As needed annually, update and refine Board Composition Matrix and align with input from the Board
- Conduct Board Needs Assessment with **Joint Nominating Committee (JNC)** annually in advance of the full search process

Director profiles and timeline

- Based on Board Composition Analysis and needs assessment, with ongoing contributions from the **JNC** as it convenes, identify priority "candidate archetypes" for directors
- Determine ideal timing for upcoming director recruitment, based on ISO New England's strategic needs and board member term limit timeline and board leadership succession imperatives
- Refine and finalize Candidate Archetypes and update position specification for current board cycle

Identify candidates

Candidate Slate Development

- For each Candidate Archetype, we then seek to identify a diverse slate of potential candidates
- We also welcome suggestions from the JNC/NEPOOL and will evaluate each recommendation regardless of the source
- We interview and vet each candidate that we intend to present to the **JNC**. We soft reference all candidates, and conduct formal references whenever possible
- A range of materials summarizing our candidate slate is presented to the **JNC**, including full resumes

JNC Assessment of Candidate(s)

- Meet with the **JNC** to identify ~6-8 top candidates per director search
- Once the **JNC** interviews candidates (typically over 2 rounds of interviews), RRA facilitates a feedback debrief to help the committee select the nominees

Final Diligence

- Complete extensive formal referencing and background check(s)
- If the **JNC** has any concerns that specific stakeholder groups may have concerns about a candidate, we work with the **JNC** to establish a process for vetting around these issues
- Respond to any diligence requests that the prospective nominees have i regards to better understanding the board's fit for their objectives

Appoint and repeat

Appoint Director

- Nomination process then continues to unfold in alignment with ISO New England process guidelines from bylaws
- Appoint successful candidate(s) to ISO New England's board

Repeat

- RRA develops and tracks an Evergreen Pipeline between search cycles, maintain a current perspective on potential candidates for future recruitment. RRA engages with these potential candidates to gauge interest and conduct preliminary vetting for future process with the **JNC**

Russell Reynolds Associates

Key Deliverables

Board Composition Matrix

- This document is an analysis of the current Board's composition and serves as a baseline for identifying current/future potential experience gaps and underrepresentation of experience on the Board based on the requirements of the bylaws and the board's view of its most pressing experiential requirements.
- The Board Composition Matrix was created at the outset of RRA's 3-Year engagement with ISO New England. A review of the Board Composition Analysis is undertaken annually as needed when directors leave/join the board. Inputs include:
  - **Director Interview:** discuss each director's professional history and current board leadership roles as well as their personal plans over the next 3–5 years (to identify potential departures outside of term limits).
  - **Definition Review:** Review the skills and experience definitions for accuracy and completeness and revise as needed
  - **RRA Analysis:** RRA analyzes the directors' skills and experiences and aligned them with the board composition matrix
  - **Director Self Assessment:** RRA then reviews with each director his/her column in the matrix and revised as needed based on new information provided to clarify competencies

Board Needs Assessment:

- The Board Needs Assessment is conducted annually and will inform the current year's director search Position Specification. Inputs include:
  - Meeting with members of the JNC to discuss the key experiential priorities for the current year's search
  - Shaping these discussions into the Candidate Archetypes document and the updated Position Specification. Both of these documents are reviewed and iterated the with the JNC until they are approved

Candidate Slate

- The list of vetted and engaged board candidates for each search cycle

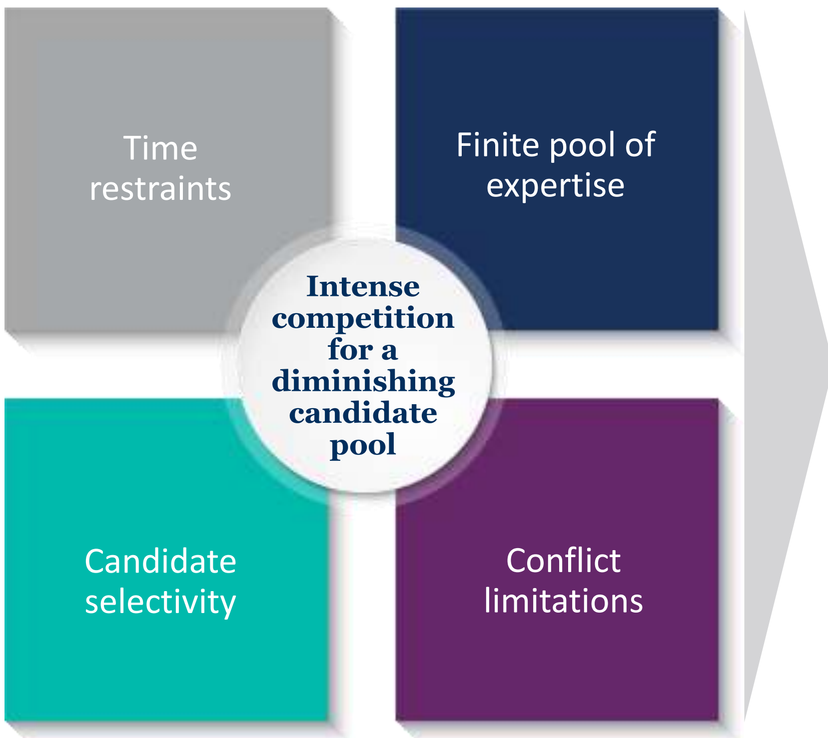
Evergreen Pipeline

- An ongoing list of potential board candidate profiles that is refreshed for new names and maintained as candidate availability/ changes over time (year over year) with future board refreshment in mind

Russell Reynolds ASSOCIATES

Evergreen Process: A Proactive Approach for Staying Ahead of Board Recruitment Needs

Typical challenges with board recruitment



Our approach to mitigate these:

- An "evergreen" process that **proactively identifies and vets candidates** in advance of their availability
- Take into account both **planned director departures and their resultant committee leadership succession implications,** as well as a structured review of **future strategy driven experiential composition needs**
- **Continual re-evaluation of the Board's composition**

Benefits

- Balance board director longevity with the **active inclusion of new thinking** on **ISO New England's** Board
- Begin to cultivate interest from candidates **months or years in advance of availability**; *particularly helpful when targeting highly desirable candidates that bring specialized skillsets to the Board*
- Support **long term board leadership succession needs**
- Allow RRA to explore a **richer pool of candidates** who may not be immediately available and/or broaden the network to include individuals at the forefront of advances perhaps in an unrelated industry.

2021 ISO New England Board Search: Candidate Archetypes

Transmission Expertise	▪ Technical expertise in transmission planning and operations remains a key area of interest. The JNC noted the need to "recognize a balance" with traditional Board executive oversight skills and having adequate technical appreciation to fully grasp core initiatives.
Markets Expertise	▪ Most JNC members indicated the need for expertise in energy markets. This could arise from the candidate's direct experience in managing assets or a trading function engaged in wholesale power or other energy markets, or from engagement in market design analysis.
Diversity	▪ The JNC unanimously highlighted the need for candidates who bring racial, gender, or ethnic diversity to the board. Such candidates would bring diversity of thought as well as important representation of the breadth of stakeholders and, ultimately, customers that ISO New England serves. There is understanding from JNC members that in order to ensure a robust slate of "board ready" diverse candidates, efforts may need to be made to look outside of the energy industry.
Energy Transition Expertise	▪ Several JNC members outlined a need for the expertise relative to the technologies and business models associated with the clean energy transition and an understanding of the associated policies and regulatory mandates.
Customer Advocate	▪ Some JNC members stated that adding an individual who has experience advocating on behalf of consumer interest is a needed point of view on the Board. This person should bring an informed view on costs considerations for customers, ideally with insight specific to utilities in New England. Such candidates would be able to effectively apply their expertise to ensure a Board-level perspective on ISO-NE's mandates of reliability and end-user value.

ISO New England Board Composition Requirements

Guiding principles across each search cycle

Sections 9 and 13 of the Participants Agreement set forth requirements for Board composition

- At least **three of the directors** shall have prior relevant experience in the **electric industry**.
- Beyond this, a **cross-section of desirable skills** and experiences is then outlined: " . . .such as, for purposes of illustration but not by way of mandate or limitation, experience in Commission electric regulatory affairs, energy industry management, corporate finance, bulk power systems, human resource administration, power pool operations, public policy, distributed generation or demand response technologies, renewable energy, consumer advocacy, environmental affairs, business management and information technologies."
- In addition, to ensure sensitivity to regional concerns, strong preference is given to identifying **candidates from New England**

These requirements are then overlaid with the ISO New England Board's need to have the **necessary expertise** to populate the following six committees of the Board:

System Planning and Reliability (SPARC)	Markets
Audit and Finance	Human Resources and Compensation
IT and Cyber	Nominating and Governance

2021-2022 Upcoming Retirements & Areas of Expertise
A snapshot view of the current composition of the board

Director (by retirement date)	(1) Electric Industry/ Transmission Experience	(2) Markets Expertise Financial Markets (F) Energy Markets (E)	(3) Top Corporate Officer Experience At least one CEO; as noted	(4) Public Service, Regulatory Experience (FERC, States)	(5) Audit Committee Financial Expert	(6) IT/Cyber Security Expertise
Kathleen Abernathy '21			X	X		
Phil Shapiro '21		X (F)	X	X	X	
Barney Rush '22	X	X (F,E)	X		X	
Vickie VanZandt '22	X		X			X
Roberto Denis '23	X		X			
Brook Colangelo '26			X			X
Mike Curran '27		X (F,E)	X (CEO)		X	X
Cheryl LaFleur '28	X	X (E)	X (CEO)	X		X
Mark Vannoy '29	X		X	X		
Gordon van Welie	X	X (E)	X (CEO)			X

Russell Reynolds ASSOCIATES

Independence Guidelines
We vet all candidates for potential conflicts of interest

The ISO New England Code of Conduct sets for a range of conflict guidelines for qualifying as an Independent Director. These include:

FERC Interlock

- FERC authorization is required for any officer or director of a public utility (including ISO-NE) seeking to simultaneously hold a position as officer or director of:
  - Another public utility
  - Any bank, trust company, banking association, or firm that is authorized by law to underwrite or participate in the marketing of securities of the public utility
  - Any company supplying electrical equipment to the public utility of that officer or director

Restriction on Securities Ownership

- No director, spouse or minor child of a director may own, control or hold with the power to vote securities of a publicly-traded market participant or affiliate
  - There is a three-part test in Section 2.1 of the Code to exclude the securities of participants with a de minimis relationship to the ISO
  - Also excluded: publicly available mutual funds, other collective funds or widely held pension funds that do not concentrate in investments in market participants
  - New directors must divest any securities deemed to be a conflict within six months

No Association with Market Participants/Affiliates

- Directors may not be "associated" with a market participant or affiliate through:
  - Employment by the director or his or her spouse as an officer, director, partner or employee of a market participant or affiliate
  - Receipt of benefits from a market participant or affiliate (other than customary retirement benefits)
  - Having a material ongoing relationship with a market participant or affiliate

Beyond These Parameters, We Assess for “Board Readiness”

We assess all potential candidates based upon our insights into high-performing board behaviors

Foundational Director Behaviors

Behaviors that are the basics for director success

Prepared & Engaged	Comes prepared, is fully present at meetings, and seeks to add value
Current & Open	Stays abreast of industry and company developments; is open to new ideas, processes and ways to solve problems
Builds Trust & Respect	Is able to build and earn the trust and respect of fellow directors
External Stakeholder Savvy	Understands external stakeholder perspectives as well as how to think about maximizing shareholder returns

Differentiating Behaviors

Behaviors that differentiate the best, most effective directors

Source: Russell Reynolds Global Board Culture Survey 2019, n = 750 corporate directors.

Russell Reynolds ASSOCIATES

Position Specification

ISO New England Inc.

Board Director

For NEPOOL Use Only

Our Client

ISO New England Inc. (ISO-NE) is a Regional Transmission Organization (RTO) and 501C3, serving the six New England states: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont. In 1997, the Federal Energy Regulatory Commission (FERC) approved ISO-NE's creation as an independent system operator (ISO) in response to federal legislation passed in the early 1990s that called for industry restructuring by creating non-discriminatory access to transmission systems and removing obstacles to wholesale electricity competition. ISO-NE was established to ensure the reliability of New England's bulk electric power system and to establish and operate the region's competitive wholesale electricity markets, which were launched in 1999.

ISO-NE's stated mission is to protect the health of New England's economy and the well-being of its people, by ensuring the constant availability of electricity today and for future generations. To achieve this, ISO-NE has three critical roles and responsibilities in New England: (Operations) keeping electricity supply and demand in balance 24/7, (Design) designing, running, and overseeing the region's wholesale electricity marketplace and (Planning) ensuring that the power system meets New England's needs over the next 10 years.

ISO-NE currently oversees a power system of 350 generating units, approximately 9,000 miles of high-voltage transmission lines that serves the six-state region, and transmission interconnections to the neighboring power systems of New York, Quebec, and New Brunswick. New England's wholesale electricity markets currently include day-ahead and real-time energy markets, a forward market for capacity, and ancillary services. In 2020, the ISO settled approximately $7.9 billion of market transactions in the wholesale electricity marketplace the ISO administers.

ISO New England is regulated by the FERC, which defines the authority, responsibilities, and services provided by ISO New England and approves the rules that guide the company. In 2003, FERC approved ISO New England's change in regulatory designation from an ISO to an RTO, giving ISO-NE authority over the development of transmission needed for system reliability and oversight of wholesale market rules and changes.

ISO New England meets the wholesale electricity demands of the 7.2 million commercial and retail electricity customers by fulfilling three primary responsibilities:

- Minute-to-minute reliable operation of New England's bulk electric power system, providing centrally dispatched direction for the generation and flow of electricity across the region's interstate high-voltage transmission lines.
- Development, oversight, and fair administration of New England's wholesale electricity marketplace, through which wholesale power is bought, sold, and traded. These competitive markets provide positive economic and environmental outcomes for consumers and improve the ability of the power system to efficiently meet consumer demand.
- Management of a comprehensive bulk power system planning process that addresses New England's power system reliability needs into the future. If market responses are not adequate to meet the identified needs, the ISO, in its role as RTO, must identify appropriate transmission infrastructure solutions that are essential for maintaining power system reliability.

FERC-approved rules for ISO New England can be found in the *ISO New England Inc. Transmission, Markets, and Services Tariff* (the ISO Tariff): https://www.iso-ne.com/participate/rules-procedures/tariff.

While ISO New England plays a critical role in the wholesale electricity markets, it is a not-for-profit organization. The ISO Tariff outlines the FERC-approved revenues the company collects for its services and sets out the cost recovery and allocation mechanisms for transmission and ancillary services in the region.

As ISO-NE enters its twenty-fourth year as an organization in 2021, it continues to operate the region's bulk electric power system and administer the region's wholesale electricity markets. Current industry challenges that ISO New England is working on with stakeholders include a Future Grid Initiative, intended to support the region's transition to clean energy through the integration of state-supported renewable resources into the regional power system and the evolution and repositioning of the region's wholesale electricity markets, which include the development of additional market products and services.

The Role

Two of ISO New England's current Directors will be rolling off the Board due to term limitations in Q3 2021 and the organization is seeking to find their successors. The newly elected Directors will be appointed to serve three-year terms that will commence in October 2021. The candidates will then be eligible for re-election for a total of two additional three-year terms, provided that there is no conflict with the Board's guidelines around the mandatory retirement age (see detail in guidelines section below).

The successful candidates will join eight other Directors, seven of whom are outside Directors, with responsibility for overseeing the financial performance, ethical standards, and managerial assets of the organization. With backgrounds including utilities, finance, regulation, communications, and academia, members of the Board play a critical role in ISO New England governance, bringing objectivity, insight, and advice and ensuring that the company is addressing issues of timely importance. Currently, the utility industry, as a whole, is undergoing a period of unprecedented transformation driven by a range of factors including a fast-evolving technology landscape, near record low commodity prices, the integration of an ever-increasing supply of renewable generation, disparate regulatory regimes, extensive consolidation, and an aging workforce. Thus, the ISO New England Board is facing an especially challenging period for defining a strategy for the organization that meets the wide range of needs and perspectives of its stakeholders. While exciting, this challenge also compels the Board to seek candidates with the highest caliber of strategic and analytical capabilities to help the company navigate through this uncharted territory.

The Board maintains an active and demanding schedule, and participation in all Board meetings is expected. The Board also engages with stakeholders and state public utility commissions throughout the year and set meetings with these groups are a part of the Board's annual agenda. The successful candidates should be prepared to completely engage in and contribute to the Board's activities. The by-laws for the Board require that three Board members serve on each committee and, typically, Board members serve on an average of three committees per Director. The standing committees for the Board are: the Nominating and Governance Committee, the Compensation and Human Resources Committee, the Audit and Finance Committee, the Markets Committee, the System Planning and Reliability

Committee, and the Information Technology and Cyber Security Committee. Additionally, special committees can be convened, and directors also participate in the Joint Nomination Committee that selects new Board members. The current schedule of Board meetings is outlined below.

2021 Board and Committee Meetings.

DATE	MEETING
January 20 -21	Board & Committee Meetings: A&F, Comp & HR, Markets, Nom & Gov, SPARC **Location:** Virtual
February 9	Comp & HR **Location:** Teleconference
February 18	Board & Committee Meeting: A&F, Nom & Gov **Location:** Virtual
March 17 -18	Board & Committee Meetings w/ NECPUC: A&F, Markets, Nom & Gov, SPARC, Special Committee on IT & Cyber Security **Location**: Virtual
May 20	Audit & Finance, Markets, Nom & Gov **Location**: Virtual
June 23	Board, Committee Meetings & NEPOOL Summer Meeting (June 22-24): Comp & HR, Markets, Nom & Gov, SPARC, Special Committee on IT & Cyber Security **Location:** Manchester Village, VT
August 19	Committee Meeting: A&F, Markets **Location**: Holyoke, MA or Teleconference
September 22 – 23	Board & Committee Meeting: A&F, Comp & HR, Markets, Nom & Gov, SPARC, Special Committee on IT & Cyber Security **Location:** Exact Location TBD *(Board retirement dinner evening of TBD)*
October 6	RSP Public Meeting **Location:** TBD
November 1 – 3	Board & Committee Meetings (includes NECPUC on the 2nd): A&F, Comp & HR, Markets, Nom & Gov, SPARC, Joint Board/NEPOOL Sector Meetings on the 3rd **Location:** Boston, MA
May 23 – 26	NECPUC Symposium (voluntary attendance) **Location:** Newport, RI
May 26	IRC Joint Board Conference **Location:** Virtual

Full details on the Board's structure and governance can be obtained by reviewing the Board's by-laws, which can be found here:

https://www.iso-ne.com/static-assets/documents/aboutiso/corp_gov/bylaws/bylaws_of_ISO_NE.pdf

Russell Reynolds Associates will also provide a copy of the by-laws upon request.

Candidate Profile

The by-laws governing the board of ISO New England require that it be composed of exceptional leaders from a spectrum of backgrounds that include technical knowledge of electric power and natural gas operations, but also commercial market operations, trading and risk management, IT, finance, and regulatory experience. Given the forthcoming waive of retirements that the board faces, the Joint Nominating Committee is taking a broad view on the expertise and experience that they desire to see in this year's candidate slate. Of particular interest to the Joint Nominating Committee are candidates with a depth of expertise in markets, ideally with energy industry experience specific to wholesale market operations; candidates who have a depth of experience in utility operations, particularly bulk power transmission planning and operations; and candidates who have played a leadership role in navigating the policies and technologies that are bringing about the transformation within the energy sector.

Diversity and richness of professional and functional expertise is of paramount importance in qualifying potential new Directors. However, the impending Board member retirements will lead to a loss of institutional knowledge and governance expertise that will amplify the need to identify candidates who bring an understanding of board operations shaped by experience serving on corporate or relevant industry boards. Candidates will ideally bring a strong customer-oriented perspective to the Board and have professional or personal ties to the New England region, though this regional connection is not a mandate for the current search process.

In terms of the personal qualifications that ISO New England seeks, candidates must have unquestionable personal ethics and integrity combined with a positive reputation within their respective industry. Candidates' experience should come from well-managed and accountable companies/organizations known for excellence in operating performance. To be a culture fit for the Board, candidates should be team-oriented, engaged and inquisitive, and must be capable of presenting diverse points of view in a constructive manner. Intellectual curiosity and a mission-driven orientation will also be essential traits for ensuring effective engagement in the highly complex and technical work that this board performs. Further, candidates should be adept at bringing out the best in their peers to promote a consensus-driven decision-making process. The new Director should be able to challenge the thinking on the Board and provide differentiated perspectives and insights but do so in a constructive and impactful way. The ISO New England Board interacts extensively with stakeholders, so Directors must display a sincere desire to work effectively within the stakeholder engagement construct.

Given the time commitment required by the ISO New England Board, Directors may find that it is difficult to fulfill their obligations to more than two additional outside boards. Further, an extensive range of conflict guidelines also limits Directors in their pursuit of outside board and employment opportunities within the energy, and to some extent financial, sectors and beyond, so thoughtful consideration of the restrictions and rules detailed in the section below are needed in determining whether the ISO New England board is a fit for prospective candidates' professional objectives.

Board Member Restrictions and Affiliation Rules

This individual will be an independent Director free of any conflicts and interlocks, as defined by FERC's "Interlock Rule" and the ISO-NE Code of Conduct, respectively.

- Interlock rule: FERC prohibits any Director of a public utility (like ISO-NE) from also holding a position as an officer or Director of another public utility or a supplier of electrical equipment to that public utility, bank, trust company, banking association, or firm authorized by law to underwrite or participate in marketing of securities of a public utility, unless FERC approves the "interlock."

  As Board members know from experience, FERC seems unwilling to waive the Interlock Rule. Accordingly, the candidate should treat this as an absolute prohibition. A similar provision in the ISO-NE Code of Conduct prohibits a Director from concurrently serving as an officer, Director, partner, or employee of a market participant or affiliate.

- ISO NE Code of Conduct ISO New England's Code of Conduct contains the following provisions relevant to the search:

  - **Relationships with Market Participants and Affiliates:** A Director cannot serve as an executive officer or Director of a market participant or affiliate. Additionally, a Director cannot receive continuing benefits (other than customary retirement-related benefits) from a market participant or affiliate.

  - **Financial Interests:** A Director or his or her spouse and minor children cannot own, control, or hold power-to-vote securities of a market participant or affiliate.

  - **Spouse's Employment:** The Code of Conduct prohibits a Director's spouse from serving as an officer, Director, or employee of a market participant or affiliate, unless the Audit and Finance Committee of the Board of Directors approves a waiver.

  - **Material ongoing business or professional relationships:** A Director may not have an ongoing relationship with a market participant or affiliate or an employee of the same. The Audit and Finance Committee of the Board of Directors determines what constitutes such relationships.

  - **Bylaws' Age Limitation:** ISO-NE's bylaws state that no person shall be eligible for election or reelection unless such person is age 70 or less at the time of election or reelection.

The ISO-NE list of market participants and affiliates will be provided by Russell Reynolds to candidates, for their review of potential conflicts, along with detailed conflict guidelines.

Search Process

The ISO elects its Board members through a nominating process that involves representatives from the ISO New England Board of Directors, the New England Power Pool (NEPOOL), and the New England Conference of Public Utilities Commissioners who compose the Joint Nominating Committee (JNC). Candidates also receive the endorsement of the NEPOOL Participants Committee. For the current search process, two rounds of interviews are expected before finalist candidates are nominated for endorsement by NEPOOL. Once NEPOOL has voted for the endorsement, the candidate would begin serving as a Director in the October 2021 Board meeting.

Compensation

The compensation schedule outlined for the ISO New England's Board of Directors is as follows:

Annual compensation, paid in quarterly instalments

Annual Retainer	$70,000
Chairman of the Board	$25,000
Committee Chairpersons	$10,000
Board Vice Chair	$5,000

Meeting fees (including teleconferences, if joining via teleconference fee is half), paid after each meeting

Board Meeting Fees	$2,000 per meeting day
Committee Meeting Fees	$1,500 per meeting day
Joint Meetings with NEPOOL and NECPUC	$1,500 per meeting day
Joint Nominating Committee Meetings	$1,500 per meeting day
Telephonic Attendance Meeting Fees	50% of the usual meeting fee
Special Meetings Special Meetings at the request of the CEO or Board	$1,500 per meeting day
Special Director Assignments Any special project or assignment at the request of the CEO and Board	$250 per hour

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MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Sebastian Lombardi and Rosendo Garza, NEPOOL Counsel

DATE: February 25, 2021

RE: Updating Offer Review Trigger Prices (ORTP) Values for FCA16

At the March 4, 2021 Participants Committee teleconference meeting, you will be asked to consider the Markets Committee's recommendation to amend NEPOOL's previously-adopted proposal relating to ORTPs, which are to be used in the sixteenth Forward Capacity Auction (FCA16). In addition, you will be asked to consider the ISO's modified set of ORTPs and related Tariff revisions. This memorandum summarizes the relevant background information, explains the voting process, and includes a form of resolution.

In addition, included with this memorandum are the following Attachments:

- Attachment A: The February 24 Markets Committee-recommended set of Tariff redlines.
- Attachment B: The ISO-proposed Tariff redlines for its modified ORTP proposal.
- Attachment C: The Markets Committee's February 24 Notice of Actions.
- Attachment D: The ISO/IMM's background materials.

PROCEDURAL BACKGROUND

Following an extended stakeholder process, on December 3, 2020, the Participants Committee considered and approved, by a 71.84% Vote in favor, a set of ORTP values and related Tariff revisions (among other parameters)[1] to be used in the Forward Capacity Market (FCM) beginning with FCA16. The NEPOOL-approved ORTP revisions differed from those the ISO favored. At the request of the ISO, NEPOOL also considered and voted the ISO-favored ORTP provisions and FCM parameters, which failed with an 18.33% Vote in favor. As a result, a jump ball[2] was established with a NEPOOL-supported alternative to the ISO's proposed set of Tariff revisions.

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[1] The additional parameters approved by NEPOOL, which included updates the Cost of New Entry (CONE), Net CONE, and Performance Payment Rate (PPR), were the same parameters favored by the ISO.

[2] In a jump ball proceeding, the ISO and NEPOOL submit both proposals to FERC on equal legal footing. *See* Participants Agreement § 11.1.5. The FERC determines which proposal is "just and reasonable and preferable." *See id.*

DEVELOPMENTS SINCE THE DECEMBER 3 PARTICIPANTS COMMITTEE VOTE

On December 11, 2020, the New England Power Generators Association filed a complaint challenging the ISO's proposed Net CONE calculation for FCA16.[3] Consequently, the ISO (in consultation with NEPOOL Counsel) decided to bifurcate its FCM parameter values filing. As noted in the ISO's December 31, 2020 transmittal letter, the ISO sought a FERC decision on those FCM parameters on which ISO and NEPOOL did not depart (i.e., CONE, Net CONE, and PPR values) in time for the FCA16 qualification process, which begins in March 2021.[4] Explaining that FERC approval of the ORTP values could wait until later in the FCA16 qualification process, the ISO committed to file the two alternative NEPOOL and ISO ORTP proposals in a subsequent jump ball filing.[5]

On December 27, 2020, the federal Consolidated Appropriations Act, 2021 (the Act) was signed into law. Among other things, this Act extended the beginning of construction deadline for the Production Tax Credit (PTC) and the Investment Tax Credit (ITC) for certain renewable resources. Because of this material change in circumstances, the ISO, working with its consultants (Concentric Energy Advisors, Inc. and Mott MacDonald), assessed the impact of the Act and, as explained further below, revised its previously-considered set of ORTP values and related Tariff revisions.

Because the ISO bifurcated its FCM parameters filings, the jump ball proceeding will be limited to the issues where NEPOOL and the ISO disagreed—the ORTPs and related Appendix A revisions. For the sake of clarity herein, the previously adopted NEPOOL alternative will be referred to as the "Dec. 3 NEPOOL ORTP Proposal."

MARKETS COMMITTEE CONSIDERATION

At the February 9–10, 2021 Markets Committee meeting, the ISO presented its initial proposed Tariff revisions resulting from the material change in circumstances caused by the Act. The ISO explained that, because the ITC eligibility was revised for offshore wind and solar technologies, its consultants re-calculated ORTPs for those technology types. The ISO further explained that, because the PTC only applied to onshore wind projects that already had a $0.000/kW-month ORTP, no change to that ORTP was proposed. The ISO also concluded that the tax law changes under the Act warranted Tariff revisions to include a new ORTP value for Combined Photovoltaic Solar and Energy Storage Device – Lithium Ion Battery, as well as additional Tariff revisions regarding the weighted average approach to calculate ORTPs for multiple technology types.

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[3] Complaint and Request for Fast-Track Process of the New England Power Generators Association, Inc., Docket No. EL21-26 (filed Dec. 11, 2020).

[4] ISO New England Inc., Updates to CONE, Net CONE, and Capacity Performance Payment Rate, Docket No. ER21-787, at 3 (filed Dec. 31, 2020).

[5] *Id.* at 41.

Thus, the ISO proposed the following changes to its previously-favored package of ORTPs and related Tariff provisions (together, the ISO's Revised ORTP Proposal):

- Two new ORTP values in Appendix A:
    - Photovoltaic Solar: $0.000/kW-month
    - Combined Photovoltaic Solar and Energy Storage Device – Lithium Ion Battery: $6.964/kW-month
- Adding Tariff language to Sections III.A.21.1.1 and III.A.21.2(c) stating that the weighted average calculation would only be used when an ORTP for the combination of technology types is not specified in the Tariff
- Proposing new Tariff language to specify the ITC percentages that would be used during the FCAs 17 and 18 ORTP adjustment for Photovoltaic Solar and Combined Photovoltaic Solar and Energy Storage Device – Lithium Ion Battery

At its February 24, 2021 meeting, the Markets Committee first considered whether, in light of the Act and proposed modifications to the ISO-favored ORTPs and related Tariff revisions, the Dec. 3 NEPOOL ORPT Proposal should also be changed. With a 71.67% Vote in favor, that Committee voted to recommend that the Participants Committee approve three changes (discussed below) to the Dec. 3 NEPOOL ORTP Proposal. In addition, at the request of the ISO, the Markets Committee also considered whether to recommend NEPOOL Participants Committee support for the ISO's Revised ORTP Proposal. That resolution failed with no Participant voting in support.

1. *Union of Concerned Scientists (UCS) (on behalf of RENEW Northeast) Amendment #1: Incorporate the Current ITC values into FCA16 ORTPs*[6]

The first amendment offered at the Markets Committee proposed to ensure that the ITC eligibility for solar and offshore wind projects (i.e., **26** percent and **30** percent, respectively) were reflected in the Dec. 3 NEPOOL ORTP Proposal. The latter technology type's ORTP remained unchanged because the Dec. 3 NEPOOL ORTP Proposal included an ORTP of $0.000/kW-month. The former technology type's ORTP, however, changed. Thus, UCS Amendment #1 modified the Dec. 3 NEPOOL ORTP Proposal by striking out the Photovoltaic Solar ORTP of $1.861/kW-month and inserting a $0.000/kW-month value (which is the same value as the ISO's modified ORTP proposal[7]). This motion to amend the Dec. 3 NEPOOL ORTP Proposal passed at the Markets Committee with a 73.81% Vote in favor.

[6] To review UCS's presentation, please click here.

[7] Although the ISO and the Markets Committee propose the same ORTP for solar resources, the Markets Committee-supported value includes an assumption of a longer economic life, an assumption that was approved by the Participants Committee when it approved the Dec. 3 NEPOOL ORTP Proposal. The ISO's new solar ORTP assumes a 20-year economic life.

2. *UCS Amendment #2: Reflecting the Solar ITC Phase Down Values in ORTP Annual Adjustments for FCAs 17 and 18*[8]

The Markets Committee next considered UCS's second amendment, which sought to add Tariff language to the Dec. 3 NEPOOL ORTP Proposal's requirement for the ISO, during the ORTP adjustments for FCAs 17 and 18, to update the PTC and ITC inputs of the capital budgeting model to reflect the most current tax law. UCS's amendment proposed additional Tariff language intended to ensure that the capital budgeting model for the photovoltaic solar resource would include 26% ITC for FCA17, 22% for FCA18, and 10% thereafter. This motion passed with a 73.71% Markets Committee Vote in favor.

3. *Advanced Energy Economy, Borrego Solar Systems, Enel X, ENGIE North America, and RENEW Northeast's Amendments to Section III.A.21.1.1*[9]

The third and final amendment to the Dec. 3 NEPOOL ORTP Proposal considered by the Markets Committee, which was jointly proposed by a number of Participants, was offered to ensure that new capacity resources composed of assets having different technology types received an ORTP based on the weighted average of the ORTPs of the asset technology types that composed the capacity resource. Specifically, co-located assets of multiple technology types registering as a single resource would receive an ORTP equal to the weighted average of the ORTPs applicable to the assets comprising the resource. For co-located assets of multiple technology types registering as separate FCM resources, the ORTPs assigned would be the applicable ORTP to the underlying technology type. To effectuate the joint amendment's purpose, Tariff language was proposed to Section III.A.21.1.1. Relatedly, the joint amendment also struck out the Combined Photovoltaic Solar and Energy Storage Device – Lithium Ion Battery Demand Capacity Resource ORTP from the Dec. 3 NEPOOL ORTP Proposal. The proponents argued that the ORTP for this demand capacity resource was inconsistent with the existing Tariff language. This third amendment passed with a Markets Committee a 75.31% Vote in favor.

With Markets Committee support for three amendments to the Dec. 3 NEPOOL ORTP Proposal, the Markets Committee then considered and, with a 71.667% Vote in favor, voted to recommend that the Participants Committee support the modified package of ORTP provisions.[10] Thus, the Participants Committee will consider whether to change its prior support for the Dec. 3 NEPOOL ORTP Proposal in favor of the modified package recommended by the Markets Committee, which is referred to herein as the "MC-recommended Modified NEPOOL ORTP Proposal."

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[8] UCS's presentation explaining its amendment can be reviewed here.

[9] The presentation fully describing the joint amendment can be accessed here.

[10] The individual Sector votes at the Markets Committee were as follows: *Generation* – 4.77% in favor, 11.93% opposed, 0 abstentions; *Transmission* – 16.7% in favor, 0% opposed, 0 abstentions; *Supplier* – 5.01% in favor, 11.69% opposed, 5 abstentions; *Publicly Owned Entity* – 16.7% in favor, 0% opposed, 0 abstentions; *Alternative Resources* – 11.79% in favor, 4.71% opposed, 0 abstentions; and *End User* – 16.7% in favor, 0% opposed, 1 abstention.

At the request of the ISO, the Markets Committee also voted on the ISO's Revised ORTP Proposal. That Proposal received a 0% Vote in favor; thus, it was not recommended by the Markets Committee.[11]

For the sake of convenience, the following table provides the Markets Committee-recommended ORTPs, as well as the ISO's updated ORTPs.

Revised ORTPs Since the December 3 NPC Vote (New ORTPs Highlighted in Green)		
Generating Capacity Resources		
Technology Type	**ISO-NE's ORTP ($/kW-month)**	**Markets Committee-Supported ORTP ($/kW-month)**
Simple Cycle Combustion Turbine	$5.366	$5.366
Combined Cycle Gas Turbine	$9.819	$9.819
On-Shore Wind	$0.000	$0.000
Off-Shore Wind	N/A[12]	$0.000
Energy Storage Device – Lithium Ion Battery	$2.923	$2.612
Photovoltaic Solar	$0.000	$0.000[13]
Combined Photovoltaic Solar and Energy Storage Device – Lithium Ion Battery	$6.964	N/A
Demand Capacity Resources		
Technology Type	**ISO-NE's ORTP ($/kW-month)**	**Markets Committee-Supported ORTP ($/kW-month)**
Load Management (Commercial / Industrial)	$0.761	
Previously Installed Distributed Generation	$0.761	
New Distributed Generation	Based on generation technology type	
On-Peak Solar	$5.425	
Combined Photovoltaic Solar and Energy Storage Device – Lithium Ion Battery	$7.376	N/A
Energy Efficiency	$0.000	

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[11] The individual Sector votes at the Markets Committee were as follows: *Generation* – 0% in favor, 16.7% opposed, 1 abstention; *Transmission* – 0% in favor, 16.7% opposed, 3 abstentions; *Supplier* – 0% in favor, 16.7% opposed, 8 abstentions; *Publicly Owned Entity* – 0% in favor, 16.7% opposed, 0 abstentions; *Alternative Resources* – 0% in favor, 16.5% opposed, 0 abstentions; and *End User* – 0% in favor, 16.7% opposed, 2 abstentions.

[12] Although the ISO inputted a 30% ITC into the capital budgeting model when evaluating the Act's impact on offshore wind resources, that technology type's ORTP under the ISO's calculation was still above the FCA starting price. As a result, the ISO did not include an offshore wind-specific ORTP in its proposed updated Tariff revisions.

[13] *See supra* note 7 and accompanying text.

THE PARTICIPANTS COMMITTEE VOTING PROCESS

Following its standard process, the starting point at the March 4 Participants Committee meeting will be to consider whether to support the MC-recommended Modified NEPOOL ORTP Proposal instead of the previously-approved Dec. 3 NEPOOL ORTP Proposal. The following form of resolution may be used to initiate Participants Committee consideration:

> RESOLVED, that the Participants Committee supports amending its previously-approved Offer Review Trigger Prices and related Tariff revisions as recommended by the Markets Committee at its February 24, 2021 meeting, and as circulated to this Committee in advance of this meeting, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

If the MC-recommended Modified NEPOOL ORTP Proposal is not further amended and that Proposal receives a 60% or greater Vote in favor, then the Modified NEPOOL ORTP Proposal will be the Participants Committee-approved alternative to the ISO's Revised ORTP Proposal. If the motion to support the MC-recommended Modified NEPOOL ORTP Proposal fails to pass, then the Dec. 3 NEPOOL ORTP Proposal will remain as NEPOOL's-approved alternative to the ISO's Proposal.

Following the Participants Committee's standard process, any member or alternate may offer an amendment to the MC-recommended Modified NEPOOL ORTP Proposal.[14] Any amendments, including an amended package, will need to receive at least a 60% Vote in favor to be supported. Participants need to be aware that, under the intended voting process, if the Participants Committee first amends the MC-recommended Modified NEPOOL ORTP Proposal at its March 4 meeting but then fails to support the amended MC-recommended Modified NEPOOL ORTP Proposal, then NEPOOL will not have an approved alternative and as your counsel we will no longer be in a position to advocate for a NEPOOL alternative to the ISO's Revised ORTP Proposal (including the Dec. 3 NEPOOL ORTP Proposal). In the event the MC-recommended Modified NEPOOL ORTP Proposal is amended and that amended proposal also receives a 60% or greater Vote in favor, then the jump ball will reflect that amended proposal.

Consistent with ISO's rights under the Participants Agreement, we expect that the ISO will request a separate vote on the ISO's Revised ORTP Proposal following Committee action on the MC-recommended Modified NEPOOL ORTP Proposal.

Given the unique and unprecedented circumstances before us, we offer Figure 1 to provide further clarity to the Participants Committee members and alternates on the contemplated voting process for the March 4 meeting on a modified alternative NEPOOL ORTP proposal.

[14] At this time, we have not been advised of any such proposed amendments.

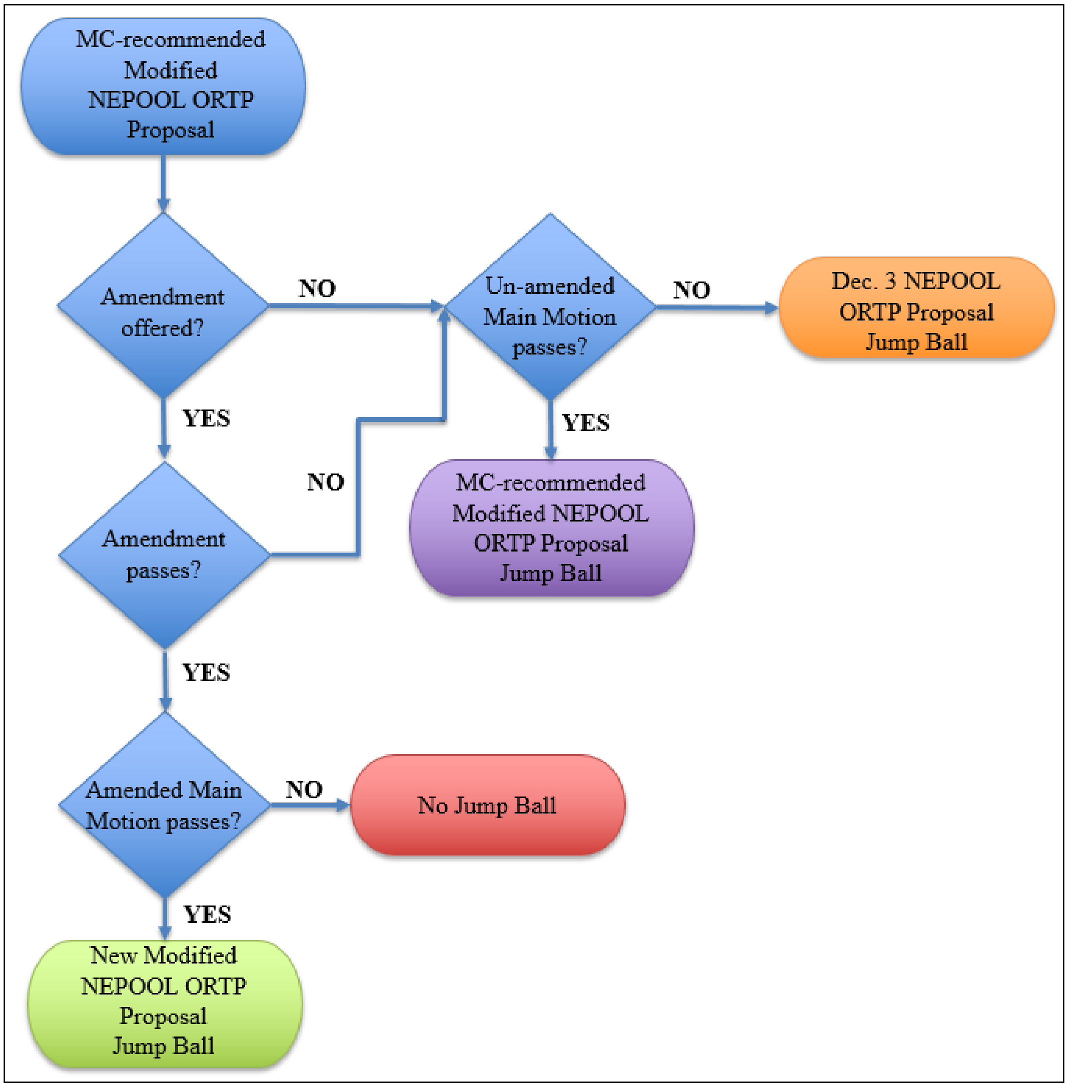

Figure 1: NPC Voting Process

If anyone wishes to offer amendments for Participants Committee consideration, please provide those amendments to NEPOOL Counsel (slombardi@daypitney.com and rgarza@daypitney.com) as soon as possible so that we can circulate them in time for member review and consideration before the meeting.

NEPOOL ORTP Proposal

- **NEPOOL-supported Tariff revisions to the ISO's ORTP proposal, as approved by the NEPOOL Participants Comimitte at its December 3, 2020 meeting, are highlighted in green.**
- **Markets Committee-recommended changes to the NEPOOL-supported Tariff revisions, as supported at the February 24, 2021 Markets Committee meeting, are highlighted in yellow.**
- **NOTE: Any remaining redlines that are not highlighted are those the ISO proposed and were approved by the Participants Committee at its December 3, 2020 meeting.**

I.2 Rules of Construction; Definitions

I.2.1. Rules of Construction:

In this Tariff, unless otherwise provided herein:

(a) words denoting the singular include the plural and vice versa;

(b) words denoting a gender include all genders;

(c) references to a particular part, clause, section, paragraph, article, exhibit, schedule, appendix or other attachment shall be a reference to a part, clause, section, paragraph, or article of, or an exhibit, schedule, appendix or other attachment to, this Tariff;

(d) the exhibits, schedules and appendices attached hereto are incorporated herein by reference and shall be construed with an as an integral part of this Tariff to the same extent as if they were set forth verbatim herein;

(e) a reference to any statute, regulation, proclamation, ordinance or law includes all statutes, regulations, proclamations, amendments, ordinances or laws varying, consolidating or replacing the same from time to time, and a reference to a statute includes all regulations, policies, protocols, codes, proclamations and ordinances issued or otherwise applicable under that statute unless, in any such case, otherwise expressly provided in any such statute or in this Tariff;

(f) a reference to a particular section, paragraph or other part of a particular statute shall be deemed to be a reference to any other section, paragraph or other part substituted therefor from time to time;

(g) a definition of or reference to any document, instrument or agreement includes any amendment or supplement to, or restatement, replacement, modification or novation of, any such document, instrument or agreement unless otherwise specified in such definition or in the context in which such reference is used;

(h) a reference to any person (as hereinafter defined) includes such person's successors and permitted assigns in that designated capacity;

(i) any reference to “days” shall mean calendar days unless “Business Days” (as hereinafter defined) are expressly specified;

(j) if the date as of which any right, option or election is exercisable, or the date upon which any amount is due and payable, is stated to be on a date or day that is not a Business Day, such right, option or election may be exercised, and such amount shall be deemed due and payable, on the next succeeding Business Day with the same effect as if the same was exercised or made on such date or day (without, in the case of any such payment, the payment or accrual of any interest or other late payment or charge, provided such payment is made on such next succeeding Business Day);

(k) words such as “hereunder,” “hereto,” “hereof” and “herein” and other words of similar import shall, unless the context requires otherwise, refer to this Tariff as a whole and not to any particular article, section, subsection, paragraph or clause hereof; and a reference to “include” or “including” means including without limiting the generality of any description preceding such term, and for purposes hereof the rule of *ejusdem generis* shall not be applicable to limit a general statement, followed by or referable to an enumeration of specific matters, to matters similar to those specifically mentioned.

I.2.2. Definitions:

In this Tariff, the terms listed in this section shall be defined as described below:

Active Demand Capacity Resource is one or more Demand Response Resources located within the same Dispatch Zone, that is registered with the ISO, assigned a unique resource identification number by the ISO, and participates in the Forward Capacity Market to fulfill a Market Participant’s Capacity Supply Obligation pursuant to Section III.13 of Market Rule 1.

Actual Capacity Provided is the measure of capacity provided during a Capacity Scarcity Condition, as described in Section III.13.7.2.2 of Market Rule 1.

Actual Load is the consumption at the Retail Delivery Point for the hour.

Additional Resource Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

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New Capacity Resource Economic Life is the number of years that is the lesser of (a) the period of time that a New Capacity Resource of a given technology type or types would reasonably be expected to operate before the resource becomes unprofitable for at least two consecutive years, (b) the expected physical operating life of the resource, or (c) 35 years.

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Offer Review Trigger Prices are the prices specified in Section III.A.21.1 of Market Rule 1 associated with the submission of New Capacity Offers in the Forward Capacity Auction.

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III.13. Forward Capacity Market.

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III.13.2. Annual Forward Capacity Auction.

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III.13.2.4. Forward Capacity Auction Starting Price and the Cost of New Entry.
The Forward Capacity Auction Starting Price is max [1.6 multiplied by Net CONE, CONE]. References in this Section III.13 to the Forward Capacity Auction Starting Price shall mean the Forward Capacity Auction Starting Price for the Forward Capacity Auction associated with the relevant Capacity Commitment Period.

CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025 ~~2021~~ is $11.874~~11.35~~/kW-month.

Net CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025 ~~2021~~ is $7.024~~8.04~~/kW-month.

CONE and Net CONE shall be recalculated ~~for the Capacity Commitment Period beginning on June 1, 2025 and~~ no less often than once every three years ~~thereafter~~. -Whenever these values are recalculated, the ISO will review the results of the recalculation with stakeholders and the new values will be filed with the Commission prior to the Forward Capacity Auction in which the new value is to apply.

Between recalculations, CONE and Net CONE will be adjusted for each Forward Capacity Auction pursuant to Section III.A.21.1.2(e) (except that the bonus tax depreciation adjustment described in Section III.A.21.1.2(e)(5) shall not apply). Prior to applying the annual adjustment for the Capacity Commitment Period beginning on June 1, 2019, Net CONE will be reduced by $0.43/kW-month to reflect the elimination of the PER adjustment. The adjusted CONE and Net CONE values will be published on the ISO's web site.

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SECTION III

MARKET RULE 1

APPENDIX A

**MARKET MONITORING,
REPORTING AND MARKET POWER MITIGATION**

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MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

***

III.A.21.1.1. Offer Review Trigger Prices for the Forward Capacity Auction.

For resources other than New Import Capacity Resources, the Offer Review Trigger Prices for the ~~twelfth Forward Capacity Auction (for the~~ Capacity Commitment Period beginning on June 1, 2025~~2021)~~ shall be as follows:

Generating Capacity Resources	
Technology Type	**Offer Review Trigger Price ($/kW-month)**
Simple Cycle ~~c~~Combustion ~~t~~Turbine	$5.366~~6.503~~
~~c~~Combined ~~c~~Cycle ~~g~~Gas ~~t~~Turbine	$9.819~~7.856~~
~~o~~On-~~s~~Shore ~~w~~Wind	$0.000~~11.025~~
Off-Shore Wind	$0.000

Energy Storage Device – Lithium Ion Battery	$2.612~~2.923~~
Photovoltaic Solar	$0.000~~1.861~~

Demand Capacity Resources~~ – Commercial and Industrial~~	
Technology Type	**Offer Review Trigger Price ($/kW-month)**
Load Management (Commercial / Industrial)~~and/or previously installed Distributed Generation~~	$0.761~~1.008~~
Previously Installed Distributed Generation	$0.761
~~n~~New Distributed Generation	~~b~~Based on generation technology type
On-Peak Solar	$5.425
~~Combined Photovoltaic Solar and Energy Storage Device – Lithium Ion Battery~~	~~$7.376~~
Energy Efficiency	$0.000

~~**Demand Capacity Resources – Residential**~~	
~~**Technology Type**~~	~~**Offer Review Trigger Price ($/kW-month)**~~
~~Load Management~~	~~$7.559~~
~~previously installed Distributed Generation~~	~~$1.008~~
~~new Distributed Generation~~	~~based on generation technology type~~

~~Energy Efficiency~~	~~$0.000~~

Other Resources	
All other technology types	Forward Capacity Auction Starting Price

Where one or more assets sharing a point of interconnection register as a New Capacity Resource that does not include all of the assets sharing the point of interconnection, the Offer Review Trigger Price for the New Capacity Resource will be assigned according only to the asset or assets comprising the New Capacity Resource.

Where a new resource is composed of assets having different technology types (including, but not limited to, a photovoltaic solar generator sharing a point of interconnection with an energy storage device participating in the energy market as one or more assets and participating in the capacity market as a single New Capacity Resource)~~,~~ the resource's Offer Review Trigger Price will be calculated in accordance with the weighted average formula in Section III.A.21.2(c).

For purposes of determining the Offer Review Trigger Price of a Demand Capacity Resource composed in whole or in part of Distributed Generation, the Distributed Generation is considered new, rather than previously installed, if (1) the Project Sponsor for the New Demand Capacity Resource has participated materially in the development, installation or funding of the Distributed Generation during the five years prior to commencement of the Capacity Commitment Period for which the resource is being qualified for participation, and (2) the Distributed Generation has not been assigned to a Demand Capacity Resource with a Capacity Supply Obligation in a prior Capacity Commitment Period.

For a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, the Offer Review Trigger Prices in the table above shall apply, based on the technology type of the External

Resource; provided that, if a New Import Capacity Resource is associated with an Elective Transmission Upgrade, it shall have an Offer Review Trigger Price of the Forward Capacity Auction Starting Price plus $0.01/kW-month.

For any other New Import Capacity Resource, the Offer Review Trigger Price shall be the Forward Capacity Auction Starting Price plus $0.01/kW-month.

III.A.21.1.2. Calculation of Offer Review Trigger Prices.

(a) The Offer Review Trigger Price for each of the technology types listed above shall be recalculated using updated data for the Capacity Commitment Period beginning on June 1, 2025 and no less often than once every three years thereafter. Where any Offer Review Trigger Price is recalculated, the Internal Market Monitor will review the results of the recalculation with stakeholders and the new Offer Review Trigger Price shall be filed with the Commission prior to the Forward Capacity Auction in which the Offer Review Trigger Price is to apply.

(b) For New Generating Capacity Resources, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is as follows. Capital costs, expected non-capacity revenues and operating costs, assumptions regarding depreciation, taxes and discount rate are input into a capital budgeting model which is used to calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Offer Review Trigger Price is set equal to the year-one capacity price output from the model. The model looks at ~~20 years of~~ real-dollar cash flows discounted at a rate (Weighted Average Cost of Capital) consistent with that expected of a project whose output is under contract (i.e., a contract negotiated at arm's length between two unrelated parties), over the New Capacity Resource Economic Life of the project.

(c) For New Demand Capacity Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above shall be the same as that used for New Generating Capacity Resources, with the following exceptions. First, the model takes account of all costs incurred by the utility and end-use customer to deploy the efficiency measure. Second, rather than energy revenues, the model recognizes end-use customer savings associated with the efficiency programs. Third, the model assumes that all costs are expensed as incurred. Fourth, the benefits realized by end-use customers are assumed to have no tax implications for the utility. Fifth, the model discounts cash flows over the Measure Life of the energy efficiency measure.

(d) For New Demand Capacity Resources other than Demand Capacity Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is the same as that used for New Generating Capacity Resources, except that the model discounts cash flows over the contract life. For Demand Capacity Resources (other than those comprised of Energy Efficiency) that are composed primarily of large commercial or industrial customers that use pre-existing equipment or strategies, incremental costs include new equipment costs and annual operating costs such as customer incentives and sales representative commissions. For Demand Capacity Resources (other than Demand Capacity Resources comprised of Energy Efficiency) primarily composed of residential or small commercial customers that do not use pre-existing equipment or strategies, incremental costs include equipment costs, customer incentives, marketing, sales, and recruitment costs, operations and maintenance costs, and software and network infrastructure costs.

(e) For years in which no full recalculation is performed pursuant to subsection (a) above, the Offer Review Trigger Prices will be adjusted as follows:

(1) For the simple cycle combustion turbine and combined cycle gas turbine technology types, ~~E~~each line item associated with capital costs that is included in the capital budgeting model will be updated to reflect changes in the Bureau of Labor Statistics Producer Price Index for Machinery and Equipment: General Purpose Machinery and Equipment (WPU114). For all other Generating Capacity Resource technology types, each line item associated with capital costs that is included in the capital budgeting model will be updated to reflect changes in the levelized cost of energy for that technology as published by Bloomberg.~~associated with the indices included in the table below:~~

~~**Cost Component**~~	~~**Index**~~
~~gas turbines~~	~~BLS-PPI "Turbines and Turbine Generator Sets"~~
~~steam turbines~~	~~BLS-PPI "Turbines and Turbine Generator Sets"~~
~~wind turbines~~	~~Bloomberg Wind Turbine Price Index~~
~~Other Equipment~~	~~BLS-PPI "General Purpose Machinery and Equipment"~~
~~construction labor~~	~~BLS "Quarterly Census of Employment and Wages" 2371 Utility System Construction Average Annual Pay:~~ – ~~Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts~~ – ~~On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine~~
~~other labor~~	~~BLS "Quarterly Census of Employment and Wages" 2211 Power Generation and Supply Average Annual Pay:~~ – ~~Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts~~ – ~~On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine~~
~~materials~~	~~BLS-PPI "Materials and Components for Construction"~~
~~electric interconnection~~	~~BLS - PPI "Electric Power Transmission, Control, and Distribution"~~
~~gas interconnection~~	~~BLS - PPI "Natural Gas Distribution: Delivered to ultimate consumers for the account of others (transportation only)"~~
~~fuel inventories~~	~~Federal Reserve Bank of St. Louis "Gross Domestic Product: Implicit Price Deflator (GDPDEF)"~~

~~(2) Each line item associated with fixed operating and maintenance costs that is included in the capital budgeting model will be associated with the indices included in the table below:~~

~~**Cost Component**~~	~~**Index**~~
~~labor, administrative and general~~	~~BLS "Quarterly Census of Employment and Wages" 2211 Power Generation and Supply Average Annual Pay:~~

	~~– Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts~~ ~~– On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine~~
~~materials and contract services~~	~~BLS-PPI "Materials and Components for Construction"~~
~~site leasing costs~~	~~Federal Reserve Bank of St. Louis "Gross Domestic Product: Implicit Price Deflator (GDPDEF)"~~

(2~~3~~) For each line item in (1) ~~and (2)~~ above, the ISO shall calculate a multiplier that is equal to the average of values published during the most recent 12 month period available at the time of making the adjustment divided by the average of the most recent 12 month period available at the time of establishing the Offer Review Trigger Prices ~~for the FCA~~ reflected in the table in Section III.A.21.1.1 ~~above~~. The value of each line item associated with capital costs ~~and fixed operating and maintenance costs included~~ in the capital budgeting model for the FCA reflected in the table in Section A.21.1.1 ~~above~~ will be adjusted by the relevant multiplier.

(3~~4~~) The energy and ancillary services offset values for gas~~each~~ technology types in the capital budgeting model shall be adjusted by inputting to the capital budgeting model the ~~most recent~~ Henry Hub natural gas futures prices, the Algonquin Citygates Basis natural gas futures prices and the Massachusetts Hub Day-Ahead Peak ~~On-Peak~~ electricity prices, as published by ICE for the first five trading days in February, for each~~the~~ month~~s in the Capacity Commitment Period~~ ~~beginning June 1~~ of the Capacity Commitment Period to which the updated value will apply~~, 2021, as published by ICE~~.

The energy and ancillary services offset values for non-gas technology types in the capital budgeting model shall be adjusted by inputting to the capital budgeting model the Massachusetts Hub Day-Ahead Peak electricity prices, as published by ICE for the first five trading days in February, for each month of the Capacity Commitment Period to which the updated value will apply.

(4~~5~~) Renewable energy credit values in the capital budgeting model shall be updated based on the first~~most recent~~ MA Class 1 REC prices published in February for the five vintages closest to the first year of the Capacity Commitment Period associated with the relevant FCA as published by SNL Financial.

(5) The bonus tax depreciation adjustment included in the financial model for the Offer Review Trigger Prices (which is 40 percent for the Capacity Commitment Period beginning on June 1, 2025), shall be 20 percent for the Capacity Commitment Period beginning on June 1, 2026, and zero for the Capacity Commitment Period beginning on June 1, 2027 and thereafter.

(6) The Investment Tax Credit input into the capital budgeting model for the Photovoltaic Solar Generating Capacity Resource shall be 26 percent for the Capacity Commitment Period beginning on June 1, 2026, 22 percent for the Capacity Commitment Period beginning on June 1, 2027, and 10 percent thereafter.

The Production Tax Credit and Investment Tax Credit inputs into the capital budgeting model, including the aforementioned input, will be updated to reflect the most current tax law at the time of the update.

(7)~~(6)~~ The capital budgeting model and the Offer Review Trigger Prices adjusted pursuant to this subsection (e) will be published on the ISO's web site.

(8)~~(7)~~ If any of the values required for the calculations described in this subsection (e) are unavailable, then comparable values, prices or sources shall be used.

III.A.21.2. New Resource Offer Floor Prices and Offer Prices.

For every new resource participating in a Forward Capacity Auction, the Internal Market Monitor shall determine a New Resource Offer Floor Price or offer prices, as described in this Section III.A.21.2.

(a) For a Lead Market Participant with a New Capacity Resource that does not submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 or III.13.1.4.1.1.2.8, the New Resource Offer Floor Price shall be calculated as follows:

For a New Import Capacity Resource (other than a New Import Capacity Resource that is (i) backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or (ii) associated with an Elective Transmission Upgrade) the New Resource Offer Floor Price shall be $0.00/kW-month.

For a New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity Resource that is associated with an Elective Transmission Upgrade, and New Demand Capacity Resource, the New Resource Offer Floor Price shall be equal to the applicable Offer Review Trigger Price.

A resource having a New Resource Offer Floor Price higher than the Forward Capacity Auction Starting Price shall not be included in the Forward Capacity Auction.

(b) For a Lead Market Participant with a New Capacity Resource that does submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 and III.13.1.4.1.1.2.8, the resource's New Resource Offer Floor Price and offer prices in the case of a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) shall be calculated as follows:

For a New Import Capacity Resource that is subject to the pivotal supplier test in Section III.A.23 and is found not to be associated with a pivotal supplier as determined pursuant to Section III.A.23, the resource's New Resource Offer Floor Price and offer prices shall be equal to the lower of (i) the requested offer price submitted to the ISO as described in Sections III.13.1.1.2.2.3 and III.13.1.3.5; or (ii) the price revised pursuant to Section III.13.1.3.5.7.

For any other New Capacity Resource, the Internal Market Monitor shall enter all relevant resource costs and non-capacity revenue data, as well as assumptions regarding depreciation, taxes, New Capacity Resource Economic Life, and discount rate into the capital budgeting model used to develop the relevant Offer Review Trigger Price and shall calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. For a new Capacity Resource with an expected New Capacity Resource Economic Life greater than the New Capacity Resource Economic Life used in Section III.A.21.1.2(b) to calculate the Offer Review Trigger Price for the corresponding technology type, the Project Sponsor shall provide sufficient documentation as described in Section III.A.21.2(b)(iv) to justify its expected New Capacity Resource Economic Life. The Internal Market Monitor shall consider the documentation provided. The Internal Market Monitor shall compare the requested offer price to this capacity price estimate and the resource's New Resource Offer Floor Price and offer prices shall be determined as follows:

(i) The Internal Market Monitor will exclude any out-of-market revenue sources from the cash flows used to evaluate the requested offer price. Out-of-market revenues are any revenues that are: (a) not tradable throughout the New England Control Area or that are restricted to resources within a particular state or other geographic sub-region; or (b) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner. Expected revenues associated with economic development incentives that are offered broadly by state or local government and that are not expressly intended to reduce prices in the Forward Capacity Market are not considered out-of-market revenues for this purpose. In submitting its requested offer price, the Project Sponsor shall indicate whether and which project cash flows are supported by a regulated rate, charge, or other regulated cost recovery mechanism. If the project is supported by a regulated rate, charge, or other regulated cost recovery mechanism, then that rate will be replaced with the Internal Market Monitor estimate of energy revenues. Where possible, the Internal Market Monitor will use like-unit historical production, revenue, and fuel cost data. Where such information is not available (e.g., there is no resource of that type in service), the Internal Market Monitor will use a forecast provided by a credible third party source. The Internal Market Monitor will review capital costs, discount rates, depreciation and tax treatment to ensure that it is consistent with overall market conditions. Any assumptions that are clearly inconsistent with prevailing market conditions will be adjusted.

(ii) For a New Demand Capacity Resource, the resource's costs shall include all expenses, including incentive payments, equipment costs, marketing and selling and administrative and general costs incurred to acquire and/or develop the Demand Capacity Resource. Revenues shall include all non-capacity payments expected from the ISO-administered markets made for services delivered from the associated Demand Response Resource, and expected costs avoided by the associated end-use customer as a direct result of the installation or implementation of the associated Asset(s).

(iii) For a New Capacity Resource that has achieved commercial operation prior to the New Capacity Qualification Deadline for the Forward Capacity Auction in which it seeks to participate, the relevant capital costs to be entered into the capital budgeting model will be the undepreciated original capital costs adjusted for inflation. For any such resource, the prevailing market conditions will be those that were in place at the time of the decision to construct the resource.

(iv) Sufficient documentation and information must be included in the resource's qualification package to allow the Internal Market Monitor to make the determinations described in this subsection (b). Such documentation should include all relevant financial estimates and cost projections for the project, including the project's pro-forma financing support data. For a New Import Capacity Resource, such documentation should also include the expected costs of purchasing power outside the New England Control Area (including transaction costs and supported by forward power price index values or a power price forecast for the applicable Capacity Commitment Period), expected transmission costs outside the New England Control

Area, and expected transmission costs associated with importing to the New England Control Area, and may also include reasonable opportunity costs and risk adjustments. For a new capacity resource that has achieved commercial operation prior to the New Capacity Qualification Deadline, such documentation should also include all relevant financial data of actual incurred capital costs, actual operating costs, and actual revenues since the date of commercial operation. For a New Capacity Resource that has an expected New Capacity Resource Economic Life greater than the New Capacity Resource Economic Life used to calculate the Offer Review Trigger Price for the relevant technology type in Section III.A.21.1.2(b), the Project Sponsor shall provide evidence to support the expected New Capacity Resource Economic Life, including but not limited to, the asset life term for such resource as utilized in the Project Sponsor's financial accounting (e.g., independently audited financial statements); or project financing documents for the resource or evidence of actual costs or financing assumptions of recent comparable projects to the extent the Project Sponsor has not executed project financing for the resource (e.g., independent project engineer opinion or manufacturer's performance guarantee); or opinions of third-party experts regarding the reasonableness of the financing assumptions used for the project itself or in comparable projects. The Project Sponsor may also rely on evidence presented in federal filings, such as its FERC Form No. 1 or an SEC Form 10-K, to demonstrate an expected New Capacity Resource Economic Life other than the New Capacity Resource Economic Life of similar projects. If there are multiple technology types in the New Capacity Resource, the New Capacity Resource Economic Life should reflect the weighted average of the New Capacity Resource Economic Life of each of the technology types. For a New Capacity Resource that is receiving an out-of-market revenue source and that is seeking a different Weighted Average Cost of Capital than the Net CONE reference unit, the Project Sponsor must submit documentation to demonstrate that the requested Weighted Average Cost of Capital is consistent with that of a resource not receiving out-of-market revenues. This documentation could include but not be limited to publicly available information sources or private information relevant to projects in North America that are not receiving out-of-market revenues. If the supporting documentation and information required by this subsection (b) is deficient, the Internal Market Monitor, at its sole discretion, may consult with the Project Sponsor to gather further information as necessary to complete its analysis. If after consultation, the Project Sponsor does not provide sufficient documentation and information for the Internal Market Monitor to complete its analysis, then the resource's New Resource Offer Floor Price shall be equal to the Offer Review Trigger Price.

(v) If the Internal Market Monitor determines that the requested offer prices are consistent with the Internal Market Monitor's capacity price estimate, then the resource's New Resource Offer Floor Price shall be equal to the requested offer price, subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vi) If the Internal Market Monitor determines that the requested offer prices are not consistent with the Internal Market Monitor's capacity price estimate, then the resource's offer prices shall be set to a level that is consistent with the capacity price estimate, as determined by the Internal Market Monitor. Any such determination will be explained in the resource's qualification determination notification and will be filed with the Commission as part of the filing described in Section III.13.8.1(c), subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vii) For New Import Capacity Resources that have been found to be associated with a pivotal supplier as determined pursuant to Section III.A.23, if the supplier elects to revise the requested offer prices pursuant to Section III.13.1.3.5.7 to values that are below the Internal Market Monitor's capacity price estimate established pursuant to subsection (v) or (vi), then the resource's offer prices shall be equal to the revised offer prices.

(c) For a new capacity resource composed of assets having different technology types the Offer Review Trigger Price shall be the weighted average of the Offer Review Trigger Prices of the asset technology types of the assets that comprise the resource, based on the expected capacity contribution from each asset technology type. Sufficient documentation must be included in the resource's qualification package to permit the Internal Market Monitor to determine the weighted average Offer Review Trigger Price.

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ISO-NE's Proposed ORTP Tariff Revisions

- **The yellow highlighted redlines are new proposed Tariff revisions.**
- **NOTE: Any remaining redlines that are not highlighted are Tariff revisions the ISO previously proposed and did not revise.**

I.2 Rules of Construction; Definitions

I.2.1. Rules of Construction:

In this Tariff, unless otherwise provided herein:

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(b) words denoting a gender include all genders;

(c) references to a particular part, clause, section, paragraph, article, exhibit, schedule, appendix or other attachment shall be a reference to a part, clause, section, paragraph, or article of, or an exhibit, schedule, appendix or other attachment to, this Tariff;

(d) the exhibits, schedules and appendices attached hereto are incorporated herein by reference and shall be construed with an as an integral part of this Tariff to the same extent as if they were set forth verbatim herein;

(e) a reference to any statute, regulation, proclamation, ordinance or law includes all statutes, regulations, proclamations, amendments, ordinances or laws varying, consolidating or replacing the same from time to time, and a reference to a statute includes all regulations, policies, protocols, codes, proclamations and ordinances issued or otherwise applicable under that statute unless, in any such case, otherwise expressly provided in any such statute or in this Tariff;

(f) a reference to a particular section, paragraph or other part of a particular statute shall be deemed to be a reference to any other section, paragraph or other part substituted therefor from time to time;

(g) a definition of or reference to any document, instrument or agreement includes any amendment or supplement to, or restatement, replacement, modification or novation of, any such document, instrument or agreement unless otherwise specified in such definition or in the context in which such reference is used;

(h) a reference to any person (as hereinafter defined) includes such person's successors and permitted assigns in that designated capacity;

(i) any reference to "days" shall mean calendar days unless "Business Days" (as hereinafter defined) are expressly specified;

(j) if the date as of which any right, option or election is exercisable, or the date upon which any amount is due and payable, is stated to be on a date or day that is not a Business Day, such right, option or election may be exercised, and such amount shall be deemed due and payable, on the next succeeding Business Day with the same effect as if the same was exercised or made on such date or day (without, in the case of any such payment, the payment or accrual of any interest or other late payment or charge, provided such payment is made on such next succeeding Business Day);

(k) words such as "hereunder," "hereto," "hereof" and "herein" and other words of similar import shall, unless the context requires otherwise, refer to this Tariff as a whole and not to any particular article, section, subsection, paragraph or clause hereof; and a reference to "include" or "including" means including without limiting the generality of any description preceding such term, and for purposes hereof the rule of *ejusdem generis* shall not be applicable to limit a general statement, followed by or referable to an enumeration of specific matters, to matters similar to those specifically mentioned.

I.2.2. Definitions:

In this Tariff, the terms listed in this section shall be defined as described below:

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Offer Review Trigger Prices are the prices specified in Section III.A.21.1 of Market Rule 1 associated with the submission of New Capacity Offers in the Forward Capacity Auction.

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III.13. Forward Capacity Market.

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III.13.2. Annual Forward Capacity Auction.

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III.13.2.4. Forward Capacity Auction Starting Price and the Cost of New Entry.
The Forward Capacity Auction Starting Price is max [1.6 multiplied by Net CONE, CONE]. References in this Section III.13 to the Forward Capacity Auction Starting Price shall mean the Forward Capacity Auction Starting Price for the Forward Capacity Auction associated with the relevant Capacity Commitment Period.

CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025 is $11.874/kW-month.

Net CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025 is $7.024/kW-month.

CONE and Net CONE shall be recalculated no less often than once every three years. Whenever these values are recalculated, the ISO will review the results of the recalculation with stakeholders and the new values will be filed with the Commission prior to the Forward Capacity Auction in which the new value is to apply.

Between recalculations, CONE and Net CONE will be adjusted for each Forward Capacity Auction pursuant to Section III.A.21.1.2(e) (except that the bonus tax depreciation adjustment described in Section III.A.21.1.2(e)(5) shall not apply). Prior to applying the annual adjustment for the Capacity Commitment Period beginning on June 1, 2019, Net CONE will be reduced by $0.43/kW-month to reflect the elimination of the PER adjustment. The adjusted CONE and Net CONE values will be published on the ISO's web site.

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SECTION III

MARKET RULE 1

APPENDIX A

MARKET MONITORING,
REPORTING AND MARKET POWER MITIGATION

***

MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

***

III.A.21.1.1. Offer Review Trigger Prices for the Forward Capacity Auction.

For resources other than New Import Capacity Resources, the Offer Review Trigger Prices for the ~~twelfth Forward Capacity Auction (for the~~ Capacity Commitment Period beginning on June 1, 2025~~1)~~ shall be as follows:

Generating Capacity Resources	
Technology Type	**Offer Review Trigger Price ($/kW-month)**
Simple Cycle ~~c~~Combustion ~~t~~Turbine	$5.366~~6.503~~
~~c~~Combined ~~c~~Cycle ~~g~~Gas ~~t~~Turbine	$9.819~~7.856~~
~~o~~On-~~s~~Shore ~~w~~Wind	$0.000~~11.025~~
Energy Storage Device – Lithium Ion Battery	$2.923
Photovoltaic Solar	$0.000
Combined Photovoltaic Solar and Energy Storage Device – Lithium Ion Battery	$6.964

Demand Capacity Resources~~ – Commercial and Industrial~~	
Technology Type	**Offer Review Trigger Price ($/kW-month)**
Load Management (Commercial / Industrial)~~and/or previously installed Distributed Generation~~	$0.761~~1.008~~
Previously Installed Distributed Generation	$0.761
~~n~~New Distributed Generation	~~b~~Based on generation technology type
On-Peak Solar	$5.425
Combined Photovoltaic Solar and Energy Storage Device – Lithium Ion Battery	$7.376
Energy Efficiency	$0.000

~~Demand Capacity Resources – Residential~~	
~~Technology Type~~	~~Offer Review Trigger Price ($/kW-month)~~
~~Load Management~~	~~$7.559~~
~~previously installed Distributed Generation~~	~~$1.008~~
~~new Distributed Generation~~	~~based on generation technology type~~
~~Energy Efficiency~~	~~$0.000~~

Other Resources	
All other technology types	Forward Capacity Auction Starting Price

Where a new resource is composed of assets having different technology types and the combination of technology types is not specified in the tables above, the resource's Offer Review Trigger Price will be calculated in accordance with the weighted average formula in Section III.A.21.2(c).

For purposes of determining the Offer Review Trigger Price of a Demand Capacity Resource composed in whole or in part of Distributed Generation, the Distributed Generation is considered new, rather than previously installed, if (1) the Project Sponsor for the New Demand Capacity Resource has participated materially in the development, installation or funding of the Distributed Generation during the five years prior to commencement of the Capacity Commitment Period for which the resource is being qualified for participation, and (2) the Distributed Generation has not been assigned to a Demand Capacity Resource with a Capacity Supply Obligation in a prior Capacity Commitment Period.

For a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, the Offer Review Trigger Prices in the table above shall apply, based on the technology type of the External Resource; provided that, if a New Import Capacity Resource is associated with an Elective Transmission Upgrade, it shall have an Offer Review Trigger Price of the Forward Capacity Auction Starting Price plus $0.01/kW-month.

For any other New Import Capacity Resource, the Offer Review Trigger Price shall be the Forward Capacity Auction Starting Price plus $0.01/kW-month.

III.A.21.1.2. Calculation of Offer Review Trigger Prices.

(a) The Offer Review Trigger Price for each of the technology types listed above shall be recalculated using updated data for the Capacity Commitment Period beginning on June 1, 2025 and no less often than once every three years thereafter. Where any Offer Review Trigger Price is recalculated, the Internal Market Monitor will review the results of the recalculation with stakeholders and the new Offer Review Trigger Price shall be filed with the Commission prior to the Forward Capacity Auction in which the Offer Review Trigger Price is to apply.

(b) For New Generating Capacity Resources, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is as follows. Capital costs, expected non-capacity revenues and operating costs, assumptions regarding depreciation, taxes and discount rate are input into a capital budgeting model which is used to calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Offer Review Trigger Price is set equal to the year-one capacity price output from the model. The model looks at 20 years of real-dollar cash flows discounted at a rate (Weighted Average Cost of Capital) consistent with that expected of a project whose output is under contract (i.e., a contract negotiated at arm's length between two unrelated parties).

(c) For New Demand Capacity Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above shall be the same as that used for New Generating Capacity Resources, with the following exceptions. First, the model takes account of all costs incurred by the utility and end-use customer to deploy the efficiency measure. Second, rather than energy revenues, the model recognizes end-use customer savings associated with the efficiency programs. Third, the model assumes that all costs are expensed as incurred. Fourth, the benefits realized by end-use customers are assumed to have no tax implications for the utility. Fifth, the model discounts cash flows over the Measure Life of the energy efficiency measure.

(d) For New Demand Capacity Resources other than Demand Capacity Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is the same as that used for New Generating Capacity Resources, except that the model discounts cash flows over the contract life. For Demand Capacity Resources (other than those comprised of Energy Efficiency) that are composed primarily of large commercial or industrial customers that use pre-existing equipment or strategies, incremental costs include new equipment costs and annual operating costs such as customer incentives and sales representative commissions. For Demand Capacity Resources (other than Demand Capacity Resources comprised of Energy Efficiency) primarily composed of residential or small commercial customers that do not use pre-existing equipment or strategies, incremental costs include equipment costs, customer incentives, marketing, sales, and recruitment costs, operations and maintenance costs, and software and network infrastructure costs.

(e) For years in which no full recalculation is performed pursuant to subsection (a) above, the Offer Review Trigger Prices will be adjusted as follows:

(1) For the simple cycle combustion turbine and combined cycle gas turbine technology types, ~~E~~each line item associated with capital costs that is included in the capital budgeting model will be updated to reflect changes in the Bureau of Labor Statistics Producer Price Index for Machinery and Equipment: General Purpose Machinery and Equipment (WPU114). For all other Generating Capacity Resource technology types, each line item associated with capital costs that is included in the capital budgeting model will be updated to reflect changes in the levelized cost of energy for that technology as published by Bloomberg.~~associated with the indices included in the table below:~~

~~Cost Component~~	~~Index~~
~~gas turbines~~	~~BLS-PPI "Turbines and Turbine Generator Sets"~~
~~steam turbines~~	~~BLS-PPI "Turbines and Turbine Generator Sets"~~
~~wind turbines~~	~~Bloomberg Wind Turbine Price Index~~
~~Other Equipment~~	~~BLS-PPI "General Purpose Machinery and Equipment"~~
~~construction labor~~	~~BLS "Quarterly Census of Employment and Wages" 2371 Utility System Construction Average Annual Pay:~~

	– ~~Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts~~ – ~~On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine~~
~~other labor~~	~~BLS "Quarterly Census of Employment and Wages" 2211 Power Generation and Supply Average Annual Pay:~~ – ~~Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts~~ – ~~On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine~~
~~materials~~	~~BLS-PPI "Materials and Components for Construction"~~
~~electric interconnection~~	~~BLS - PPI "Electric Power Transmission, Control, and Distribution"~~
~~gas interconnection~~	~~BLS - PPI "Natural Gas Distribution: Delivered to ultimate consumers for the account of others (transportation only)"~~
~~fuel inventories~~	~~Federal Reserve Bank of St. Louis "Gross Domestic Product: Implicit Price Deflator (GDPDEF)"~~

~~(2) Each line item associated with fixed operating and maintenance costs that is included in the capital budgeting model will be associated with the indices included in the table below:~~

~~**Cost Component**~~	~~**Index**~~
~~labor, administrative and general~~	~~BLS "Quarterly Census of Employment and Wages" 2211 Power Generation and Supply Average Annual Pay:~~ – ~~Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts~~ – ~~On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine~~
~~materials and contract services~~	~~BLS-PPI "Materials and Components for Construction"~~
~~site leasing costs~~	~~Federal Reserve Bank of St. Louis "Gross Domestic Product: Implicit Price Deflator (GDPDEF)"~~

(~~3~~2) For each line item in (1) ~~and (2)~~ above, the ISO shall calculate a multiplier that is equal to the average of values published during the most recent 12 month period available at the time of making the adjustment divided by the average of the most recent 12 month period available at the time of establishing the Offer Review Trigger Prices ~~for the FCA~~ reflected in the table in Section III.A.21.1.1 ~~above~~. The value of each line item associated with capital costs ~~and fixed operating and maintenance costs included~~ in the capital budgeting model for the FCA reflected in the table in Section A.21.1.1 ~~above~~ will be adjusted by the relevant multiplier.

(~~4~~3) The energy and ancillary services offset values for gas ~~each~~ technology types in the capital budgeting model shall be adjusted by inputting to the capital budgeting model the ~~most recent~~ Henry Hub natural gas futures prices, the Algonquin Citygates Basis natural gas futures prices and the Massachusetts Hub Day-Ahead Peak ~~On-Peak~~ electricity prices, as published by ICE for the first five trading days in February, for each ~~the~~ months ~~in the Capacity Commitment Period beginning June 1~~ of the Capacity Commitment Period to which the updated value will apply~~, 2021, as published by ICE~~.

The energy and ancillary services offset values for non-gas technology types in the capital budgeting model shall be adjusted by inputting to the capital budgeting model the Massachusetts Hub Day-Ahead Peak electricity prices, as published by ICE for the first five trading days in February, for each month of the Capacity Commitment Period to which the updated value will apply.

(~~5~~4) Renewable energy credit values in the capital budgeting model shall be updated based on the first ~~most recent~~ MA Class 1 REC prices published in February for the five vintages closest to the first year of the Capacity Commitment Period associated with the relevant FCA as published by SNL Financial.

(5) The bonus tax depreciation adjustment included in the financial model for the Offer Review Trigger Prices (which is 40 percent for the Capacity Commitment Period beginning on June 1, 2025), shall be 20 percent for the Capacity Commitment Period beginning on June 1, 2026, and zero for the Capacity Commitment Period beginning on June 1, 2027 and thereafter.

(6) The investment tax credit adjustment included in the financial model for the Offer Review Trigger Prices for the photovoltaic solar and combined photovoltaic solar and energy storage device – lithium ion battery Generating Capacity Resource technology types (which is 26 percent for the Capacity Commitment Period beginning on June 1, 2025), shall be 22 percent for the Capacity Commitment Period beginning on June 1, 2026, and 10 percent for the Capacity Commitment Period beginning on June 1, 2027 and thereafter.

(~~6~~7) The capital budgeting model and the Offer Review Trigger Prices adjusted pursuant to this subsection (e) will be published on the ISO's web site.

(~~7~~8) If any of the values required for the calculations described in this subsection (e) are unavailable, then comparable values, prices or sources shall be used.

III.A.21.2. New Resource Offer Floor Prices and Offer Prices.

For every new resource participating in a Forward Capacity Auction, the Internal Market Monitor shall determine a New Resource Offer Floor Price or offer prices, as described in this Section III.A.21.2.

(a) For a Lead Market Participant with a New Capacity Resource that does not submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 or III.13.1.4.1.1.2.8, the New Resource Offer Floor Price shall be calculated as follows:

> For a New Import Capacity Resource (other than a New Import Capacity Resource that is (i) backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or (ii) associated with an Elective Transmission Upgrade) the New Resource Offer Floor Price shall be $0.00/kW-month.
>
> For a New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity Resource that is associated with an Elective Transmission Upgrade, and New Demand Capacity Resource, the New Resource Offer Floor Price shall be equal to the applicable Offer Review Trigger Price.

A resource having a New Resource Offer Floor Price higher than the Forward Capacity Auction Starting Price shall not be included in the Forward Capacity Auction.

(b) For a Lead Market Participant with a New Capacity Resource that does submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 and III.13.1.4.1.1.2.8, the resource's New Resource Offer Floor Price and offer prices in the case of a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) shall be calculated as follows:

> For a New Import Capacity Resource that is subject to the pivotal supplier test in Section III.A.23 and is found not to be associated with a pivotal supplier as determined pursuant to Section III.A.23, the resource's New Resource Offer Floor Price and offer prices shall be equal to the

lower of (i) the requested offer price submitted to the ISO as described in Sections III.13.1.1.2.2.3 and III.13.1.3.5; or (ii) the price revised pursuant to Section III.13.1.3.5.7.

For any other New Capacity Resource, the Internal Market Monitor shall enter all relevant resource costs and non-capacity revenue data, as well as assumptions regarding depreciation, taxes, and discount rate into the capital budgeting model used to develop the relevant Offer Review Trigger Price and shall calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Internal Market Monitor shall compare the requested offer price to this capacity price estimate and the resource's New Resource Offer Floor Price and offer prices shall be determined as follows:

(i) The Internal Market Monitor will exclude any out-of-market revenue sources from the cash flows used to evaluate the requested offer price. Out-of-market revenues are any revenues that are: (a) not tradable throughout the New England Control Area or that are restricted to resources within a particular state or other geographic sub-region; or (b) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner. Expected revenues associated with economic development incentives that are offered broadly by state or local government and that are not expressly intended to reduce prices in the Forward Capacity Market are not considered out-of-market revenues for this purpose. In submitting its requested offer price, the Project Sponsor shall indicate whether and which project cash flows are supported by a regulated rate, charge, or other regulated cost recovery mechanism. If the project is supported by a regulated rate, charge, or other regulated cost recovery mechanism, then that rate will be replaced with the Internal Market Monitor estimate of energy revenues. Where possible, the Internal Market Monitor will use like-unit historical production, revenue, and fuel cost data. Where such information is not available (e.g., there is no resource of that type in service), the Internal Market Monitor will use a forecast provided by a credible third party source. The Internal Market Monitor will review capital costs, discount rates, depreciation and tax treatment to ensure that it is consistent with overall market conditions. Any assumptions that are clearly inconsistent with prevailing market conditions will be adjusted.

(ii) For a New Demand Capacity Resource, the resource's costs shall include all expenses, including incentive payments, equipment costs, marketing and selling and administrative and general costs incurred to acquire and/or develop the Demand Capacity Resource. Revenues shall include all non-capacity payments expected from the ISO-administered markets made for services delivered from the associated Demand Response Resource, and expected costs avoided by the associated end-use customer as a direct result of the installation or implementation of the associated Asset(s).

(iii) For a New Capacity Resource that has achieved commercial operation prior to the New Capacity Qualification Deadline for the Forward Capacity Auction in which it seeks to participate, the relevant capital costs to be entered into the capital budgeting model will be the undepreciated original capital costs adjusted for inflation. For any such resource, the prevailing market conditions will be those that were in place at the time of the decision to construct the resource.

(iv) Sufficient documentation and information must be included in the resource's qualification package to allow the Internal Market Monitor to make the determinations described in this subsection (b). Such documentation should include all relevant financial estimates and cost projections for the project, including the project's pro-forma financing support data. For a New Import Capacity Resource, such documentation should also include the expected costs of purchasing power outside the New England Control Area (including transaction costs and supported by forward power price index values or a power price forecast for the applicable Capacity Commitment Period), expected transmission costs outside the New England Control Area, and expected transmission costs associated with importing to the New England Control Area, and may also include reasonable opportunity costs and risk adjustments. For a new capacity resource that has achieved commercial operation prior to the New Capacity Qualification Deadline, such documentation should also include all relevant financial data of actual incurred capital costs, actual operating costs, and actual revenues since the date of commercial operation. If the supporting documentation and information required by this subsection (b) is deficient, the Internal Market Monitor, at its sole discretion, may consult with the Project Sponsor to gather further information as necessary to complete its analysis. If after consultation, the Project Sponsor does not provide sufficient documentation and information for the Internal Market Monitor to complete its analysis, then the resource's New Resource Offer Floor Price shall be equal to the Offer Review Trigger Price.

(v) If the Internal Market Monitor determines that the requested offer prices are consistent with the Internal Market Monitor's capacity price estimate, then the resource's New Resource Offer

Floor Price shall be equal to the requested offer price, subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vi) If the Internal Market Monitor determines that the requested offer prices are not consistent with the Internal Market Monitor's capacity price estimate, then the resource's offer prices shall be set to a level that is consistent with the capacity price estimate, as determined by the Internal Market Monitor. Any such determination will be explained in the resource's qualification determination notification and will be filed with the Commission as part of the filing described in Section III.13.8.1(c), subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vii) For New Import Capacity Resources that have been found to be associated with a pivotal supplier as determined pursuant to Section III.A.23, if the supplier elects to revise the requested offer prices pursuant to Section III.13.1.3.5.7 to values that are below the Internal Market Monitor's capacity price estimate established pursuant to subsection (v) or (vi), then the resource's offer prices shall be equal to the revised offer prices.

(c) For a new capacity resource composed of assets having different technology types and the combination of the technology types is not specified in the tables in Section III.A.21.1.1, the Offer Review Trigger Price shall be the weighted average of the Offer Review Trigger Prices of the asset technology types of the assets that comprise the resource, based on the expected capacity contribution from each asset technology type. Sufficient documentation must be included in the resource's qualification package to permit the Internal Market Monitor to determine the weighted average Offer Review Trigger Price.

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ISO new england

memo

To: NEPOOL Participants Committee

From: Jay Dwyer, Acting Secretary, NEPOOL Markets Committee (MC)

Date: February 25, 2021

Subject: Actions of the MC

This memo is notification to the Participants Committee of the following actions taken by the MC at its February 24, 2021 meeting. All sectors had a quorum.

1. **(Agenda Item 2) Forward Capacity Auction (FCA) 16 Offer Review Trigger Prices (ORTPs)**

ACTION: RECOMMEND SUPPORT

(Vote 1 – Passed (Agenda Item 2(b)(i) - Union of Concerned Scientists (on behalf of RENEW Northeast) Amendment #1: Incorporate current Investment Tax Credit values into FCA 16 ORTPs))

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

RESOLVED, that the Markets Committee recommends to the Participants Committee support that the previously adopted NEPOOL-approved Offer Review Trigger Price (ORTP) proposal from the December 3, 2020 Participants Committee meeting be amended to reflect changes to Tariff section III.A.21.1.1 of Market Rule 1 as contained in the materials provided by the Union of Concerned Scientists (on behalf of RENEW Northeast), to revise the ORTPs for FCA 16 to reflect the Investment Tax Credit changes in recent tax law changes, as circulated for this meeting, with those further changes recommended by this Committee and such further non-substantive changes as the Chair and Vice-Chair may approve.

The motion to amend the previously adopted NEPOOL-approved ORTP proposal was voted by roll call. The motion passed with a vote of 73.814% in favor. The individual Sector votes were Generation (4.771% in favor, 11.929% opposed, 0 abstentions), Transmission (16.700% in favor, 0.000% opposed, 0 abstentions), Supplier (7.157% in favor, 9.543% opposed, 7 abstentions), Publicly Owned Entity (16.700% in favor, 0.000% opposed, 0 abstentions), Alternative Resources (11.786% in favor, 4.714% opposed, 0 abstentions), and End User (16.700% in favor, 0.000% opposed, 1 abstention).

(Vote 2 – Passed (Agenda Item 2(b)(ii) - Union of Concerned Scientists (on behalf of RENEW Northeast) Amendment #2: Reflect Solar Investment Tax Credit Phase Down Values in ORTP Annual Updates for FCA 17 and 18))

Before the once-amended motion could be voted, it was moved and seconded by the Markets Committee to amend the once-amended motion as follows:

RESOLVED, that the Markets Committee recommends to the Participants Committee support that the previously adopted NEPOOL-approved Offer Review Trigger Price (ORTP) proposal from the December 3, 2020 Participants Committee meeting be amended to reflect changes to Tariff section III.A.21.1.2 of Market Rule 1 as contained in the materials provided by the Union of Concerned Scientists (on behalf of RENEW Northeast), to reflect the solar Investment Tax Credit phase down values in ORTP annual updates for FCA 17 and 18, as circulated for this meeting, with those further changes recommended by this Committee and such further non-substantive changes as the Chair and Vice-Chair may approve.

The motion to amend the once-amended previously adopted NEPOOL-approved ORTP proposal was voted by roll call. The motion passed with a vote of 73.715% in favor. The individual Sector votes were Generation (5.567% in favor, 11.133% opposed, 1 abstention), Transmission (16.700% in favor, 0.000% opposed, 1 abstention), Supplier (6.263% in favor, 10.438% opposed, 6 abstentions), Publicly Owned Entity (16.700% in favor, 0.000% opposed, 0 abstentions), Alternative Resources (11.786% in favor, 4.714% opposed, 0 abstentions), and End User (16.700% in favor, 0.000% opposed, 2 abstentions).

(Vote 3 – Passed (Agenda Item 2(b)(iii) - Advanced Energy Economy, Borrego Solar Systems, Enel X, and ENGIE North America (on behalf of themselves and RENEW Northeast) Amendment: Maintain for FCA 16 the existing Tariff treatment of ORTP determination for resources with a shared point of interconnection))

Before the twice-amended motion could be voted, it was moved and seconded by the Markets Committee to amend the twice-amended motion as follows:

RESOLVED, that the Markets Committee recommends to the Participants Committee support that the previously adopted NEPOOL-approved Offer Review Trigger Price (ORTP) proposal from the December 3, 2020 Participants Committee meeting be amended to reflect changes to Tariff section III.A.21.1.2 of Market Rule 1 as contained in the materials provided by the Union of Concerned Scientists (on behalf of RENEW Northeast), to reflect the solar Investment Tax Credit phase down values in ORTP annual updates for FCA 17 and 18, as circulated for this meeting, with those further changes recommended by this Committee and such further non-substantive changes as the Chair and Vice-Chair may approve.

The motion to amend the twice-amended previously adopted NEPOOL-approved ORTP proposal was voted by roll call. The motion passed with a vote of 75.305% in favor. The individual Sector votes were Generation (7.157% in favor, 9.543% opposed, 0 abstentions), Transmission (16.700% in favor, 0.000% opposed, 0 abstentions), Supplier (6.263% in favor, 10.438% opposed, 6 abstentions), Publicly Owned Entity (16.700% in favor, 0.000% opposed, 0 abstentions), Alternative Resources (11.786% in favor, 4.714% opposed, 0 abstentions), and End User (16.700% in favor, 0.000% opposed, 1 abstention).

(Vote 4 – Passed (Three-time amended NEPOOL ORTP proposal))

The three-time amended previously adopted NEPOOL-approved ORTP proposal was voted. The three-time amended proposal passed with a vote of 71.667% in favor. The individual Sector votes were Generation (4.771% in favor, 11.929% opposed, 0 abstentions), Transmission (16.700% in favor, 0.000% opposed, 0 abstentions), Supplier (5.010% in favor, 11.690% opposed, 5 abstentions), Publicly Owned Entity (16.700% in favor, 0.000% opposed, 0 abstentions), Alternative Resources (11.786% in favor, 4.714% opposed, 0 abstentions), and End User (16.700% in favor, 0.000% opposed, 1 abstention).

(Vote 5 – Failed (Agenda Item 2(a) – ISO-NE ORTPs)

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

RESOLVED, that the Markets Committee recommends to the Participants Committee that the ISO's Offer Review Trigger Price (ORTP) proposal from the December 3, 2020 Participants Committee meeting be amended to reflect changes to Section III.A.21 of the Tariff as contained in the materials provided by ISO New England, Inc., to incorporate new ORTP categories, ITC values used for future Forward Capacity Auctions, and note when the weighted average approach will be used to calculate the ORTP for multiple technologies, 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 voted by roll call. The motion failed to pass with a vote of 0.000% in favor. The individual Sector votes were Generation (0.000% in favor, 16.700% opposed, 1 abstention), Transmission (0.000% in favor, 16.700% opposed, 3 abstentions), Supplier (0.000% in favor, 16.700% opposed, 8 abstentions), Publicly Owned Entity (0.000% in favor, 16.700% opposed, 0 abstentions), Alternative Resources (0.000% in favor, 16.500% opposed, 0 abstentions), and End User (0.000% in favor, 16.700% opposed, 2 abstentions).

ISO new england

memo

To: NEPOOL Markets Committee

From: Deborah Cooke, Principal Analyst

Date: February 18, 2021

Subject: Updates to the Offer Review Trigger Prices (WMPP ID: 139)

The ISO is requesting a vote on Tariff revisions to update its Offer Review Trigger Prices (ORTPs) proposed for use in the sixteenth Forward Capacity Auction (FCA 16) for the 2025-26 Capacity Commitment Period.

On December 27, 2020, the Consolidated Appropriations Act (the Act) was signed into law, which included material changes to Investment Tax Credit (ITC) provisions for certain renewable technologies. In reviewing the recent federal legislation and its impacts on relevant ISO-proposed FCA 16 ORTPs, the analysis showed the ITC provisions affected two Generating Capacity Resource technology types: **photovoltaic solar,** and **combined photovoltaic solar and energy storage device – lithium ion battery ("combined solar-battery")**. Therefore, the ISO-proposed Tariff revisions incorporate two new ORTP technologies for those Generating Capacity Resources and clarify how the ITC values resulting from the Act will be used in the ORTP interim updates (for FCA 17 and FCA 18) for the new ORTP technology types. In developing these ORTPs, the ISO has been responsive to stakeholder feedback and has revised its proposed ORTP for the combined solar-battery technology type to reflect the decoupled operation of the facility after five years when the ITC benefit expires.

With the addition of the new ORTP for the combined solar-battery, the proposed Tariff revisions also update the applicable conditions when the Internal Market Monitor will use a specified ORTP or the weighted-average approach to calculate an ORTP for multiple technology types. The ISO has indicated that it will use specified technology ORTPs when it is available (under the starting price) as it appropriately reflects the costs associated with the resource configuration based on a "bottoms up" calculation and therefore provides a more accurate application of the minimum offer price rule (MOPR) than the megawatt-weighted average price methodology for co-located resources without a specified ORTP.

The proposed changes that the committee are being asked to consider were presented at the February 9-10, 2021 MC meeting (agenda item 5: https://www.iso-ne.com/event-details?eventId=143983).

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memo

To: NEPOOL Markets Committee

From: Internal Market Monitor

Date: February 5, 2021

Subject: FCA 16 Co-Located Resource Offer Review Trigger Price

At the December 3, 2020 NEPOOL Participants Committee meeting, participants asked the Internal Market Monitor (IMM) how it plans to review New Resource Offer Floor Price requests from co-located resources for the sixteenth Forward Capacity Auction (FCA 16). The IMM committed to providing further clarity prior to commencing the FCA 16 New Resource Offer Floor Price reviews.

In the interim since the December Participants Committee meeting, revisions to the Investment Tax Credit (ITC) were made in the recently enacted Consolidated Appropriations Act, 2021. In turn, this prompted ISO New England (ISO) to revisit the Offer Review Trigger Price (ORTP) calculations for impacted technologies, including co-located resources. As a result, the IMM is presented with another opportunity to address the review of New Resource Offer Floor Price requests from co-located resources below the relevant technology ORTP.

The ISO and its consultant (Concentric Energy Advisors or CEA) reviewed the changes to the ITC. They determined that the Combined Photovoltaic Solar and Energy Storage Device – Lithium Ion Battery technology, which was previously identified as having an ORTP greater than the starting price of the FCA, will now have an ORTP lower than the starting price.[1] Therefore, the IMM will clarify how Offer Floor Price requests from solar plus lithium ion battery facilities will be reviewed and how requests for other combinations of co-located resource technologies will be reviewed.

For solar plus lithium ion battery facilities, the new ORTP listed in the Tariff for that category will be the ORTP for seeking entry into the Forward Capacity Market (FCM). Registering the co-located facility as one capacity resource or as two separate capacity resources will not change the application of the ORTP category, as these resources share costs and constraints. The "bottoms up" development of this specific ORTP category appropriately reflects the costs associated with this resource configuration and will provide a more accurate application of the minimum offer price rule (MOPR) than the megawatt-weighted

[1] ORTP categories for "Solar" and "Combined Photovoltaic Solar and Energy Storage Device – Lithium Ion Battery" will be added to Appendix A of the ISO New England Tariff (Section III.A.21.1.1) to reflect a price below the starting price for these technologies.

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average price methodology set forth in Tariff Section III.A.21.2(c) for co-located resources without a specified ORTP.

For other combinations of co-located resource technologies without a specified ORTP in the Tariff, the IMM will price the ORTP and Offer Floor Price in accordance with the capacity weighted average of the technology specific ORTPs as described in Tariff Section III.A.21.2(c). This weighting will be applied if the facility is registered as one capacity resource or as two capacity resources. Below are examples of this calculation.

In its proposed Tariff revisions, the ISO is also revising the language in Tariff Sections III.A.21.1.1 and III.A.21.2(c) to clarify that the IMM will calculate a weighted average ORTP if a new resource is composed of assets of different technologies and does not have an ORTP specified in Section III.A.21.1.1 of the Tariff.

Technology Type	**ORTP ($/kW-m)**	**Capacity (MW)**
On-Shore Wind	$0.000	15
Energy Storage Device - Lithium Ion Battery	$2.923	5
Weighted ORTP		**$0.731**

Technology Type	**ORTP ($/kW-m)**	**Capacity (MW)**
Off-Shore Wind	$11.874 [2]	250
Energy Storage Device - Lithium Ion Battery	$2.923	75
Weighted ORTP		**$9.808**

[2] This example illustrates a drawback with the weighted average approach where one technology's ORTP is administratively set to the starting price. This approach results in a calculated value that is artificially low, reflecting the truncation of a calculated ORTP down to the auction starting price. This issue may be addressed in the future should the need arise.

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DRAFT

ISO-NE NET CONE AND ORTP ANALYSIS

AN EVALUATION OF THE NET COST OF NEW ENTRY AND OFFER REVIEW TRIGGER PRICE PARAMETERS TO BE USED IN THE FORWARD CAPACITY AUCTION

FCA-16 AND FORWARD

CONCENTRIC ENERGY ADVISORS, INC.

MOTT MACDONALD

ADDENDUM

FEBRUARY 2021

TABLE OF CONTENTS

TABLE OF TABLES

Section 1: Summary

A. Overview

This addendum to the Net CONE and ORTP Analysis Report (Report) is required to provide detail around the calculation of the solar photovoltaic (solar PV) and co-located resource Offer Review Trigger Price (ORTP) values. The original report, dated December 2020, did not include these ORTP values as both of the estimated values were above the estimated Forward Capacity Auction (FCA) starting price based on information that was known at the time the values were calculated.

On December 27, 2020, The Consolidated Appropriations Act, 2021 (the Act) was signed into law, providing an extension of the beginning of construction deadline for the Production Tax Credit (PTC) and the Investment Tax Credit (ITC) for certain types of facilities. These changes have impacted the ORTP calculations and have resulted in both solar PV resources and co-located resources (defined as combined solar PV and battery resources with a single point of interconnection) having an ORTP value below the assumed FCA starting price. The details on these calculations are described below.

B. Summary of Recommendations

Based on our analysis, we recommend the ORTP values for solar PV and co-located resources shown in Table 1 below.

Table 1: ORTP Summary for Specific Resources (2025$)[1]

Reference Technology	Nominal Installed Capacity (MW)	Qualified Capacity (MW)	Installed Cost 2019$/kW	Real ATWACC	Gross CONE (2025$/kW-mo)	Revenue Offsets (2025$/kW-mo)	Net CONE (2025$/kW-mo) Installed	Net CONE (2025$/kW-mo) Qualified	ORTP (2025$/kW-mo)
Solar PV	20	3.8	1,524	4.3%	9.228	9.368	(0.141)	(0.748)	0.000
Co-Located Solar PV/Battery	10	5.9	1,441	4.3%	11.175	7.037	4.139	6.964	6.964

[1] The values shown assume the continuation of the Forward Reserves Market (FRM).

Section 2:
ORTP Study – Solar PV and Co-Located Resources

A. Approach

The objective of the ORTP study was to develop ORTP values for FCA-16 for the 2025/2026 Capacity Commitment Period. The recommended ORTP values presented below were set at the low end of the competitive range of expected values to strike a reasonable balance by only subjecting resource offers that appear commercially implausible absent out-of-market revenues to Internal Market Monitor (IMM) review. In addition, consistent with Open Access Transmission Tariff (Tariff) requirements, all resources were assumed to have a contract for their output.[2]

B. Financial Assumptions

The calculation of ORTP values for the solar PV and co-located resources requires a real discount rate to translate uncertain future cash-flows to a levelized revenue requirement. The financial assumptions used in the ORTP analysis, which are consistent with the financial assumptions used for all of the resources for which an ORTP value was calculated, are shown in Table 2 below.[3]

Table 2: ORTP Financial Assumptions

ROE	11.0%
COD	4.5%
Capital structure:	
Debt weight	60%
Equity weight	40%
WACC	7.1%
Nominal ATWACC	6.4%
Real ATWACC	4.3%

C. PTC/ITC for Qualifying Resources

The Act, enacted in December of 2020, provides tax credits to eligible renewable energy resources in the form of a Production Tax Credit (PTC) or an Investment Tax Credit (ITC). The PTC is not available to facilities that begin construction after December 31, 2020. Accordingly, the PTC is not considered in this ORTP analysis. However, the ORTP study does include the value of the ITC for the solar PV and co-located resources, as shown below.

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2 Market Rule 1 Appendix A Section III.A.21.1.2
3 Brattle 2014, Concentric 2017.

Table 3: ITC Assumptions

YEAR CONSTRUCTION BEGINS	ITC
2019	30%
2020	26%
2021	26%
2022	26%
2023	22%
After 2023	10%

D. Project Life

ORTP resources were assumed to have a project life of 20 years. While it is possible for different resource technologies to have varying project life assumptions, it is important to have consistent financial assumptions across resource types in order to evaluate these ORTP values on a comparable basis. This assumption is consistent with FERC guidance in PJM in the Minimum Offer Price Rule (MOPR) proceeding, where the FERC found that "default MOPR values should maintain the same basic financial assumptions, such as the 20-year asset life, across resource types" in keeping with the Commission's previous determination "that standardized inputs are a simplifying tool appropriate for determining default offer price floors…. "it is reasonable to maintain these basic financial assumptions for default offer price floors in the capacity market to ensure resource offers are evaluated on a comparable basis."[4]

E. ORTP Technical Specifications

i. Solar PV

Based on consultation with Mott MacDonald, the solar PV facility was assumed to be a 20 MW facility located in Connecticut. The assumed size of the solar facility was based on recent and expected entry by similar resource types in the FCA. Connecticut was selected as an appropriate location for the solar facility because there are currently similar facilities of this type located nearby. The solar PV facility was assumed to consist of 69,984 400-Watt modules mounted on fixed racks at a tilt of 30 degrees. Power was assumed be transmitted to a central switchyard, converted to AC, transformed up to 115 kV, and injected into the site adjacent 115 kV network.

The solar PV scope of work included fixed position solar PV arrays, as opposed to single-axis solar tracking designs. This fixed position design was selected because solar tracking has been found to be difficult to justify on a cost basis due to the historically low irradiance that occurs in the New

4 Order Establishing Just and Reasonable Rate, Docket Nos. EL16-49-000, EL18-178-000, December 19, 2019, pg. 63.

England region. Fixed position solar arrays are also consistent with a majority of the solar projects already developed in the New England region, as well as solar projects participating in recent FCAs.

ii. Co-Located

The combined solar PV and battery facility selected for the ORTP analysis was a 5 MW solar PV facility with a 5 MW and 10 MWh Lithium Ion battery storage system. The PV system consists of 17,496 PV modules and 2 Lithium Ion battery storage containers that contain 106 Lithium Ion racks located in Southeastern Massachusetts. The chosen location reflects submittals in recent FCAs.

F. Capital/Operating Costs

The table below summarizes operating costs for the solar PV and co-located ORTP units, described in further detail in the following sections. The capital cost estimates for each ORTP resource are also described in detail below.

Table 4 : Summary of ORTP Operating Costs (2025$ Levelized)

	SOLAR PV	CO-LOCATED
$/kW-year		
Property Taxes	1.36	1.28
Site Leasing	9.98	9.97
Insurance	4.59	4.31
Fixed O&M (LTSA plus ongoing O&M)	14.86	43.52
Total Fixed Expenses	**30.79**	**59.09**
($/kW-month)		
Property Taxes	0.11	0.11
Site Leasing	0.83	0.83
Insurance	0.38	0.36
Fixed O&M (LTSA plus ongoing O&M)	1.24	3.63
Total Fixed Expenses	**2.57**	**4.92**

i. Solar

To estimate capital costs for the reference solar PV unit, Concentric reviewed recently developed and current planned projects in New England to assess the appropriate size and location. We then consulted with Mott MacDonald to estimate capital costs for the reference solar PV unit. The largest components of the solar PV unit's capital costs include major equipment, racking system, foundations, SCADA and monitoring systems, electrical plant, interconnection, testing/energization, and other indirect costs as well as owner's costs. These estimates are based on Mott MacDonald's proprietary database of project costs. This database is continuously developed using active Mott MacDonald Solar PV projects. A summary of the assumed overnight capital costs for the solar PV unit are included in Table 5 below.

Table 5: Reference Solar PV Overnight Costs (2019$, in millions)

COST COMPONENT	SOLAR
EPC Costs	
Civil/Structural/Architectural	1.3
Electrical/Instrumentation Costs	1.6
Construction Management	0.8
Major Equipment - Wind Turbines, PV Modules, PV Inverters, PV Racks, Batteries	15.1
Solar SCADA & Monitoring	0.2
Testing & Energization	0.1
Other Indirect Costs	2.5
Project Contingency	1.1
Owners Development Costs	0.7
Total EPC	**23.5**
Non-EPC Costs	
Owner's Contingency	0.07
Electrical Interconnection	5.7
Electrical System Upgrade Costs/Substation Upgrades	0.0
Financing Fees (4% of costs financed through debt)	0.9
Working Capital (1% of EPC costs)	0.2
Total Non-EPC	**7.0**
Total Overnight Capital Costs	**30.5**
$/KW	**1,524**

Concentric estimated fixed operating and maintenance (O&M) costs for the solar PV resource through consultation with Mott MacDonald and a review of solar leasing agreements. Land lease costs are typically negotiated and are therefore difficult to calculate. Concentric reviewed data from several publicly available solar PV land lease agreements to estimate a reasonable range of land lease costs on a $/acre basis. The range of these costs was $7,500/MW/year to $38,100/MW/year. For purposes of the ORTP study, Concentric focused on the lower half of available land lease costs. The average of this selection was approximately $10,000/MW-year, which was also relatively close to the land lease costs for the project reviewed in Connecticut (the location of the reference resource used in the ORTP study). This resulted in a land leasing cost of approximately $1,500/acre or $9.98/kW-year.

It was determined that a property tax rate of 1% was representative of projects that have entered into PILOT agreements with local cities and towns. This rate was applied to an average of net plant values on an annual basis. Concentric also reviewed property taxes for Windham County, Connecticut to ensure the reasonableness of the ORTP property tax assumption. Property taxes for Windham County from 2018-2020 range from 2.0% to 4.3%, with an average of 2.84%. A 1% tax rate based on a PILOT agreement is sufficiently lower than this range. Based on this assumed rate, the property taxes for the solar farm were estimated at approximately $15,000 per year, or $1.36/kW-year.

Insurance costs were assumed to be 0.3% of installed costs, consistent with the other technologies evaluated in this study. Annual insurance costs were estimated to be approximately $83,000 in 2025 dollars, or $4.59/kW-year.

Long Term Service Agreement (LTSA) and ongoing maintenance costs were assumed to be $14.86/kW-year in 2025$ based on consultation with Mott MacDonald. To check the reasonableness of this assumption, Concentric also reviewed several publicly available studies which include estimates of solar PV fixed O&M costs. The results of this review ranged confirmed the assumed cost as a conservative, low-end of the range assumption.

Each of the above assumptions are an estimation of costs, since information on each of these cost categories is very limited and extremely site specific. Based on these assumptions, we calculated a levelized fixed O&M cost for the reference solar farm of $2.57/kw-month.

ii. Co-Located

Through consultation with Mott MacDonald, we estimated capital costs for the combined battery and solar PV facility based on available information in their database as well as any publicly available information on recently developed projects. Mott MacDonald's proprietary database of project costs was utilized to develop this estimate. This database is continuously developed using active Mott MacDonald combined projects. The assumed facility's construction costs fall into the following major categories: major equipment, foundations, plant electrical, site work, substation and tie line, general conditions, testing and energization, and indirect costs (which include a 10% project contingency). **Error! Reference source not found.** below contains our assumed overnight capital cost for the reference combined battery storage and photovoltaic project.

The below estimate is based on an AC-coupled system as this is representative of what has recently entered the market. The AC to DC ratio currently in the interconnection queue is approximately 50/50. Operationally, the AC-coupled system is more flexible from a power marketing standpoint, so Mott MacDonald believes the assumption of an AC-coupled system is reasonable.

Table 6: Reference Co-located Resource Overnight Costs (2019$, in millions)

COST COMPONENT	CO-LOCATED RESOURCE
EPC Costs	
Civil/Structural/Architectural	0.6
Electrical/Instrumentation Costs	0.5
Construction Management	0.8
Major Equipment - Wind Turbines, PV Modules, PV Inverters, PV Racks, Batteries	7.2
Solar SCADA & Monitoring	0.2
Testing & Energization	0.1
Other Indirect Costs	1.7
Project Contingency	1.0
Owners Development Costs	0.7
Total EPC Cost	**12.89**
Non-EPC Costs	-
Owner's Contingency	0.07
Electrical Interconnection	0.8
Electrical System Upgrade Costs/Substation Upgrades	0.0
Financing Fees (4% of costs financed through debt)	0.5
Working Capital (1% of EPC costs)	0.1
Total Non-EPC	**$1.52**
Total Overnight Capital Costs	10.0
$/KW	**$1,441**

Concentric estimated fixed O&M costs for the combined battery storage and solar PV facility through consultation with Mott MacDonald and the use of assumptions consistent with the other relevant ORTPs - standalone solar and battery facilities. Long-term service agreement (LTSA) and ongoing maintenance expenses, which include augmentation costs, were assumed to be approximately $43.52/kW-year ($2025).

Public documentation and data on leasing costs for co-located systems are very limited, so Concentric applied the same $10,000/MW leasing estimate from the solar ORTP calculation. We assumed that 10 acres of land would be leased at a cost of approximately $100,000 or approximately $2,850/acre, consistent with the per-MW cost used for the solar unit.

The total fixed O&M expense for co-located resources was calculated to be approximately $59.09/kW-year or $4.92/kW-mo.

G. Revenue Offsets for ORTP Generating Resources

This section summarizes the estimated revenue offsets used for the solar PV and co-located resources. ORTP revenue offsets come from one or more of the following potential revenue streams: energy and ancillary services (E&AS) revenues, Pay for Performance (PFP) revenues, and Renewable Energy Credit (REC) revenues. All of the E&AS estimates for the ORTP resources were developed with simplified dispatch models that used historical energy prices during the 2017-2019 period that were adjusted with an Energy/Reserve Scarcity adjustment. The prices used in the ORTP dispatch models do not include an LOE adjustment since the ISO-NE Tariff does not require that ORTP units be modeled at criterion.

i. Scarcity

Estimated revenues from energy and reserve shortages were added back as a separate line item outside of the ORTP dispatch models. The Energy/Reserves Scarcity adder for the ORTP units assumed 7.4 scarcity hours, which is based on current excess supply conditions in New England. The Energy/Reserve Scarcity unit adders are shown in Table 7.

Table 7 : ORTP Energy/Reserve Scarcity Adjustment

Unit	Availability Factor	Adjustment $/kW-mo
Solar	47.81%	0.25
Co-Located	72.90%	0.39

ii. Pay for Performance

PFP revenues for the solar PV and co-located resources was calculated in same way as the CONE units, with updated parameters. Scarcity hours were reduced from 11.3 to 7.4. Balancing ratios were also adjusted downward. The values for the solar PV and co-located resources are shown in the table below.

Table 8 : Resource-Specific Values

Technology	Performance Payment Rate ($/MWh)	Scarcity Weighted [A]	Average Balancing Ratio	Net Performance Payments ($/kW-mo)
Solar	8,782	47.8%	0.816	0.47
Co-located	8,782	72.9%	0.816	0.71

In addition to calculating the expected performance value for each resource, the expected incremental PFP revenues earned by the solar and co-located resources must account for the seasonal variation in the Capacity Supply Obligation (CSO) that these units receive. Assuming that the unit receives a seasonal CSO MW equal to its qualified capacity amount, the percent of nameplate having a CSO is applied on the same scarcity-hour specific dimension.

iii. E&AS: Solar Resource

The solar PV facility is modeled as located in Connecticut. Historical generation data from existing solar facilities in ISO-NE was used to estimate an hourly generation profile for the solar unit. The hourly generation profile is based on a daily average hourly capacity factor (i.e., one 24-hour generation profile for each month) of solar facilities in Massachusetts and Connecticut in each month during the 2017-2019 period for all facilities with a commercial online date of January 2016 or later. The solar PV facility's E&AS revenues were calculated using the same dispatch logic as the onshore wind unit. The solar PV unit offered 53% of its generation into the day-ahead market and 100% of its output into the real-time market, with variable O&M costs assumed to be zero. Given the unit's location, the solar dispatch model used prices from Connecticut zone adjusted with the Energy/Reserve Scarcity adjustment.

iv. E&AS: Co-Located Resource

The co-located resource has a maximum injection capacity of 5 MW, and 10 MWh of storage capability. (i.e., the battery is capable of injecting 10 MWh into the grid from a full state of charge). However, given the battery's 86% roundtrip efficiency, the battery's nominal storage capability is 11.63 MWh (10/0.86 = 11.63 MWh). The battery is assumed to follow a strategy to maximize its expected revenues, where the battery arbitrages intra-day price differences and charges from the solar array for the first five years of operation, after which time the battery and solar resources operate independently.

The same market assumptions used to develop revenues for the stand-alone battery and solar PV technologies were applied when calculating the revenues in years six through twenty, when the two technologies operate independently. Specifically, the battery resource participates in the day-ahead and real-time energy markets. In addition, this resource is eligible to be designated for real-time ten-minute spinning reserves and is assigned to provide ten-minute non-spinning reserves in the Forward Reserve Market. The battery resource also provides regulation services.

While the dispatch logic used for the co-located resource is consistent with that utilized for the stand-alone battery and solar PV resources, the co-located resource has a 5 MW interconnection limit. Therefore, the total output in any specific hour should be capped at 5 MW. An analysis confirmed that the interconnection limit was exceeded in only 51 hours over the course of the three years modeled (0.1% of all hours), with an impact on overall annual revenues of less than $5,000,[5] and an impact on the resulting ORTP of less than $0.04/kW-mo. Since the ORTP represents the low-end

[5] The revenue impact was calculated assuming that the battery output was constrained in the hours when the sum of the battery plus solar generation exceeded 5 MW. However, this does not include potential revenues available to the battery by dispatching remaining available energy in later hours when no facility interconnection constraint existed, which would decrease the overall impact.

price of the competitive range, the uncapped revenues from the dispatch models were used in the revenue offsets for years six through twenty.

Regulation revenues for the independent battery were calculated outside of the dispatch model and included as a standalone adder. The battery's estimated annual regulation revenues are $102,427 per year in 2019 dollars.[6] ISO-NE prepared this estimate based on the assumption that the battery would provide 11% of its 5 MW capacity for regulation. The same net average payment rate used for the stand-alone battery of $21.26/MWh was applied to the co-located resource.

The co-located resource is modeled in Southeastern Massachusetts. The same hourly generation profile used for the solar unit was used to derive energy revenues for the period of time during which the solar portion of the co-located resource is decoupled from the battery.

v. Renewable Energy Credits

Revenue offsets for solar PV and co-located resources include RECs. The REC revenues for these resources are the product of an estimated REC price and the unit's size and annual capacity factor. To estimate the REC price, Concentric relied on historical price data for MA Class I REC indices for the 2016 - 2020 vintages.[7] Concentric calculated the average price for each REC vintage based on all trades available at the time of the analysis. Concentric then averaged those five estimates (normalized to 2019$) to produce a single REC price and then escalated that to 2025 dollars.[8] The annual REC prices were used to calculate annual REC revenues for the solar PV and co-located resources. The REC price was also used in the dispatch models to establish the hourly offer prices of each unit. The resulting REC price is $29.32/MWh.

H. ORTP Summary

A summary of the ORTP values for the evaluated technologies are shown in Table 9 below.

Table 9: Summary of ORTP Values

Reference Technology	Nominal Installed Capacity (MW)	Qualified Capacity (MW)	Installed Cost 2019$/kW	Real ATWACC	Gross CONE (2025$/kW-mo)	Revenue Offsets (2025$/kW-mo)	Net CONE (2025$/kW-mo Installed)	Net CONE (2025$/kW-mo Qualified)	ORTP (2025$/kW-mo)
Solar PV	20	3.8	1,524	4.3%	9.228	9.368	(0.141)	(0.748)	0.000
Co-Located	10	5.9	1,441	4.3%	11.175	7.037	4.139	6.964	6.964

[6] The battery's estimated regulation revenues in 2025 dollars is $115,349.
[7] REC price data sourced from SNL Financial.
[8] Though RECs are traded beyond their vintage year, our average does not include those prices as they would have skewed the estimate downward.

NEPOOL PARTICIPANTS COMMITTEE
MAR 4, 2021 MEETING, AGENDA ITEM #6
Attachment D4

Offer Review Trigger Prices

Revisions to address new Federal Investment Tax Credit provisions for certain technologies

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Offer Review Trigger Prices

WMPP ID: 139

Proposed Effective Date: June 1, 2025 (CCP 16)

- The recalculation of the Offer Review Trigger Prices (ORTPs) was recently performed for the 2025-2026 Capacity Commitment Period (CCP 16)
  - Voted at the December 3, 2020 Participants Committee
- On December 27, 2020, the Consolidated Appropriations Act was signed into law, which included significant changes to Investment Tax Credit (ITC) provisions for certain renewable technologies
  - These changes impacted certain ORTP values as discussed by Concentric Energy Advisors at the February 9-10, 2021 MC meeting
- This presentation provides:
  - Responses to stakeholder questions from the February 9-10, 2021 Markets Committee
  - Updated modeling assumptions for the ORTP calculation for the co-located resource, in response to stakeholder concerns
  - A summary of Tariff revisions relating to the revised ORTPs

From February 9-10 presentation

Background

- Under the revised tax provisions, the ITC was revised for off-shore wind and solar technologies
- The ORTP values for these technologies were revisited to account for the tax credit changes
  - Revised values calculated by Concentric Energy Advisors
- Additionally, the Production Tax Credit was extended one year for on-shore wind units
  - 60% for projects beginning construction by 12/31/2021
  - Does not impact the on-shore wind ORTP of $0.000

STAKEHOLDER QUESTIONS

Responses to stakeholder questions from the February 9-10, 2021 Markets Committee meeting:

- *Revenue assumptions in the calculation of the co-located technology ORTP*
- *Impact of jump ball on retirement bids*

Updated revenue modeling for the co-located ORTP to reflect additional ITC considerations

Stakeholder Concern:
It is reasonable that the co-located solar and battery will be "decoupled" after 5 years, when the ITC benefit expires. Prior modeling reflected continued coupled operation; this underestimates revenues, and results in a higher ORTP.

Response:

- The ITC is applied to installed costs, which are depreciated using the 5-year MACRS schedule, so that after 5 years the installed costs are fully depreciated and no further benefit is available
- Therefore, we agree decoupled operation after 5 years is a reasonable assumption, and the revenues for the co-located ORTP have been revised (*continued on next slide)*

Stand-alone solar and battery dispatch models were used to estimate revenues for decoupled operation in years 6-20

- The market-participation assumptions and calculations for the stand-alone solar and battery were applied
  - Adjusted for unit size and locational energy prices
- The other detailed assumptions (for years 6-20) are the same as those reviewed with the Markets Committee previously:
  - Solar: price-taker (intermittent power), using hourly generation profile of stand-alone solar
  - Battery: decoupled asset provides energy, regulation, real-time ten-minute spinning reserves, and participates in Forward Reserve Market
    - Energy: 89% of capacity (accounting for regulation)
    - Regulation: based on 11% of capacity
    - Real-time reserves: 5 MW ten-minute spinning reserves designation
    - Forward Reserve Market: 5 MW ten-minute non-spinning reserve

Stand-alone solar and battery dispatch models were used to estimate revenues for decoupled operation in Years 6-20 *(cont.)*

- Revenues from co-located operation and stand-alone operation used in revised discounted cash flow model
  - 5 years co-located revenues + 15 years stand-alone revenues
- Two additional dispatch models (reflecting Year 6-20 revenues for the solar and battery) have been updated accordingly
  - These are provided with the Market Committee materials
- Updated discounted cash flow model has also been provided
  - Also available with the Markets Committee materials
- Revised co-located solar + battery ORTP = **$6.964 / kW-mo.**

The co-located solar + battery ORTP is more accurate than a weighted average ORTP

- The co-located solar + battery ORTP reflects a "bottom's up" calculation specific to this configuration
- The following important factors contribute to the differences between the co-located solar + battery ORTP and a weighted average of the separate solar ORTP and battery ORTP values
  - First five years, the solar output is used first to charge the battery
    - Solar generation occurs during the day when prices are higher
    - Battery discharges when prices are lower
    - Unit does not provide reserves or regulation
  - Fixed and installed costs reflect the two different technology types

Impact on retirement bids from varying ORTP values

Concern:
The final ORTP categories and values may impact participation in FCA 16, which in turn will inform retirement and permanent de-list bid submittals. A FERC ruling may not be received prior to retirement and permanent de-list bid window close. Will participants be able to modify bids after the window closes?

- Retirement and Permanent De-List Bids window: March 5 – March 12, 2021

Response:

- Participants may submit up to three different prices (with supporting documentation) in their Retirement De-List Bids, Permanent De-List Bids, and Test Price submissions, based on the following cases:
  - ISO's proposed ORTP values (IMM base case assumption)
  - NEPOOL proposed ORTP values (Alternative case assumption)
  - ORTP filing rejected (Rejections assumption)

See "Impact of Offer Review Trigger Price Jump Ball Filing on Retirement Bids" memo from Internal Market Monitor, provided with Markets Committee materials

Show of Interest ORTP categories for FCA 16 participation will reflect ISO proposed groups

Stakeholder question:
New capacity resources indicate an ORTP category when submitting the Show of Interest (SOI). FERC ruling may not be received prior to SOI window close; what categories will appear? What if a technology specific category is not available?

- SOI window: April 9 – April 23, 2021

Response:

- The ORTP technology categories proposed by the ISO will be reflected in the Forward Capacity Tracking System
- If a specific technology category is not available, participants can select "All other technology types"
  - ISO will re-categorize the technology category as applicable based upon the FERC ruling on the jump-ball ORTP filing (expected in May, prior to the new capacity submission window)

SUMMARY OF REVISIONS AND PROPOSED TARIFF REVISIONS

Summary of updates and revisions to the Tariff

1) Two new Generating Capacity Resource ORTP categories will be created
   – Solar
   – Combined Photovoltaic Solar and Energy Storage Device – Lithium Ion Battery
2) As ORTPs for specific combinations of technology types are specified in the Tariff, a modification is being made to clarify that the weighted average ORTP calculation will only be used for combinations of technology types without a specific ORTP
3) New language added to specify the ITC values used in the FCA 17 and FCA 18 interim updates
   – Reflect scheduled changes of ITC values in recently enacted provisions

Summary of Proposed Tariff Changes ORTPs

Revised from February 9-10 presentation

Tariff Section	Description of Change
III.A.21.1.1 Offer Review Trigger Prices for the Forward Capacity Auction	• Add ORTP values for the Capacity Commitment Period beginning June 1, 2025 for the following Generating Capacity Resource technologies: ◦ Solar: **$0.000** ◦ Combined Photovoltaic and Lithium Ion Battery: **$6.964** • Clarify that the weighted average calculation is used only when an ORTP for the combination of technology types is not specified
III.A.21.1.2 (e)(6)	• New section detailing the ITC values to be used for solar and combined photovoltaic/lithium-ion battery technologies for the FCA 17 and FCA 18 interim updates
III.A.21.2 (c)	• Clarify that the weighted average calculation is used only when an ORTP for the combination of technology types is not specified

Conclusion

- Two new ORTP technologies will be included for Generating Capacity Resources, reflecting revised ITC values available due to recent changes in tax law
  - Solar
  - Co-located solar/lithium-ion battery
- Revenues for the co-located ORTP value now reflect decoupled operation after 5 years
- Tariff revisions:
  - Reflect the amended ORTP values
  - Clarify that a weighted average of individual technology ORTPs will be applied when an ORTP is not specified for the combination of technology types
  - Address the ITC values that will be used in the interim updates of solar and combined solar/battery technology projects participating in FCAs 17 and 18

Stakeholder Schedule

Stakeholder Committee and Date	Scheduled Project Milestone
Markets Committee February 9-10, 2021	• Review impacts of revised ITC on ORTP values • Discuss proposed Tariff revisions
Markets Committee February 24, 2021	• MC vote on updated ORTP values and Tariff language reflecting impacts of the modified Investment Tax Credit
Participants Committee March 4, 2021	• PC vote on amended ORTP values and Tariff language to reflect impacts of the modified Investment Tax Credit
March 2021	FERC Filing

Questions

Acronyms Used in this Presentation

CCP = Capacity Commitment Period

FCA = Forward Capacity Auction

ITC = Investment Tax Credit

ORTP = Offer Review Trigger Price

PV = Photovoltaic

SOI = Show of Interest

memo

To: NEPOOL Participants Committee

From: Mark Karl, Vice President Market Development and Settlements

Date: March 2, 2021

Subject: ISO Revisions to the Offer Review Trigger Price for Co-located Resources for FCA 16 (CCP 2025-2026)

Over the course of the February 2021 Markets Committee (MC) meetings, ISO New England heard the concerns raised by stakeholders regarding the vetting of the various inputs and assumptions used in developing the Offer Review Trigger Price (ORTP) for the Combined Photovoltaic Solar and Energy Storage Device – Lithium Ion Battery ("co-located ORTP").

Although the ISO previously reviewed the development of these ORTP values with stakeholders, we understand that the ISO's proposal may benefit from additional time to evaluate and discuss the methodology and assumptions employed. Therefore, the newly proposed co-located ORTPs (in both the Generating Capacity Resource and Demand Capacity Resource categories[1]) for FCA 16 will not be included in the ORTP values filed by ISO New England.

The revised Tariff language for the NEPOOL Participants Committee will reflect the removal of these ORTP values. Accordingly, the language proposed by the ISO in February clarifying that a weighted average ORTP value will not be applied when an ORTP is available for specific combinations of technology types has been removed, as it is now moot.

[1] The Generating Capacity Resource and Demand Capacity Resource ORTPs share some similar inputs and assumptions and, therefore, it is reasonable that the same concerns raised in regards to the Generating Capacity Resource ORTP would also impact the Demand Capacity Resource ORTP.

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Non-Municipal Market Participant is defined in Section II of the ISO New England Financial Assurance Policy.

Non-PTF Transmission Facilities (Non-PTF) are the transmission facilities owned by the PTOs that do not constitute PTF, OTF or MTF.

Non-Qualifying means a Market Participant that is not a Credit Qualifying Market Participant.

Notice of RBA is defined in Section 6.3.2 of the ISO New England Billing Policy.

Notification Time is the time required for a Generator Asset to synchronize to the system from the time a startup Dispatch Instruction is received from the ISO.

Northeastern Planning Protocol is the Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol on file with the Commission and posted on the ISO website at the following URL: www.iso-ne.com/static-assets/documents/2015/07/northeastern_protocol_dmeast.doc.

NPCC is the Northeast Power Coordinating Council.

Obligation Month means a time period of one calendar month for which capacity payments are issued and the costs associated with capacity payments are allocated.

Offer Data means the scheduling, operations planning, dispatch, new Resource, and other data, including Generator Asset, Dispatchable Asset Related Demand, and Demand Response Resource operating limits based on physical characteristics, and information necessary to schedule and dispatch Generator Assets, Dispatchable Asset Related Demands, and Demand Response Resources for the provision or consumption of energy, the provision of other services, and the maintenance of the reliability and security of the transmission system in the New England Control Area, and specified for submission to the New England Markets for such purposes by the ISO.

Offer Review Trigger Prices are the prices specified in Section III.A.21.1 of Market Rule 1 associated with the submission of New Capacity Offers in the Forward Capacity Auction.

purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those having distinct Capacity Clearing Prices as a result of constraints between modeled Capacity Zones binding in the running of the Forward Capacity Auction. Where a modeled constraint does not bind in the Forward Capacity Auction, and as a result adjacent modeled Capacity Zones clear at the same Capacity Clearing Price, those modeled Capacity Zones shall be a single Capacity Zone used for all purposes of the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals.

(b) For all Forward Capacity Auctions beginning with the seventh Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2016) the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those described in Section III.12.4.

III.13.2.4. Forward Capacity Auction Starting Price and the Cost of New Entry.
The Forward Capacity Auction Starting Price is max [1.6 multiplied by Net CONE, CONE]. References in this Section III.13 to the Forward Capacity Auction Starting Price shall mean the Forward Capacity Auction Starting Price for the Forward Capacity Auction associated with the relevant Capacity Commitment Period.

CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025 is $11.874/kW-month.

Net CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025 is $7.024/kW-month.

CONE and Net CONE shall be recalculated no less often than once every three years. Whenever these values are recalculated, the ISO will review the results of the recalculation with stakeholders and the new values will be filed with the Commission prior to the Forward Capacity Auction in which the new value is to apply.

Between recalculations, CONE and Net CONE will be adjusted for each Forward Capacity Auction pursuant to Section III.A.21.1.2(e) (except that the bonus tax depreciation adjustment described in Section

III.A.21.1.2(e)(5) shall not apply). Prior to applying the annual adjustment for the Capacity Commitment Period beginning on June 1, 2019, Net CONE will be reduced by $0.43/kW-month to reflect the elimination of the PER adjustment. The adjusted CONE and Net CONE values will be published on the ISO's web site.

III.13.2.5. Treatment of Specific Offer and Bid Types in the Forward Capacity Auction.

III.13.2.5.1. Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Capacity Resources.

A New Capacity Offer (other than one from a Conditional Qualified New Resource) clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction if the Capacity Clearing Price is greater than or equal to the price specified in the offer, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. An offer from a Conditional Qualified New Resource clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6, if all of the following conditions are met: (i) the Capacity Clearing Price is greater than or equal to the price specified in the offer; (ii) capacity from that resource is considered in the determination of clearing as described in Section III.13.2.3.2(f); and (iii) such offer minimizes the costs for the associated Capacity Commitment Period, subject to Section III.13.2.7.7(c).

The amount of capacity that receives a Capacity Supply Obligation through the Forward Capacity Auction shall not exceed the quantity of capacity offered from the New Generating Capacity Resource, New Import Capacity Resource, or New Demand Capacity Resource at the Capacity Clearing Price.

III.13.2.5.2. Bids and Offers from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources.

III.13.2.5.2.1. Permanent De-List Bids and Retirement De-List Bids.

(a) Except as provided in Section III.13.2.5.2.5, a Permanent De-List Bid, Retirement De-List Bid or Proxy De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

The Internal Market Monitor shall review offers from new resources in the Forward Capacity Auction as described in this Section III.A.21.

III.A.21.1. Offer Review Trigger Prices.

For each new technology type, the Internal Market Monitor shall establish an Offer Review Trigger Price. Offers in the Forward Capacity Auction at prices that are equal to or above the relevant Offer Review Trigger Price will not be subject to further review by the Internal Market Monitor. A request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price must be submitted in advance of the Forward Capacity Auction as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 or III.13.1.4.1.1.2.8 and shall be reviewed by the Internal Market Monitor as described in this Section III.A.21.

III.A.21.1.1. Offer Review Trigger Prices for the Forward Capacity Auction.

For resources other than New Import Capacity Resources, the Offer Review Trigger Prices for the ~~twelfth Forward Capacity Auction (for the~~ Capacity Commitment Period beginning on June 1, 2025~~1)~~ shall be as follows:

Generating Capacity Resources	
Technology Type	**Offer Review Trigger Price ($/kW-month)**
Simple Cycle ~~c~~Combustion ~~t~~Turbine	$5.366~~6.503~~
~~c~~Combined ~~c~~Cycle ~~g~~Gas ~~t~~Turbine	$9.819~~7.856~~
~~o~~On-~~s~~Shore ~~w~~Wind	$0.000~~11.025~~
Energy Storage Device – Lithium Ion Battery	$2.923
Photovoltaic Solar	$0.000
~~Combined Photovoltaic Solar and Energy Storage Device – Lithium Ion Battery~~	~~$6.964~~[A1]

Demand Capacity Resources~~ – Commercial and Industrial~~	
Technology Type	**Offer Review Trigger Price ($/kW-month)**
Load Management (Commercial / Industrial)~~and/or previously installed Distributed Generation~~	$0.761~~1.008~~
Previously Installed Distributed Generation	$0.761

~~n~~New Distributed Generation	~~b~~Based on generation technology type
On-Peak Solar	$5.425
~~Combined Photovoltaic Solar and Energy Storage Device – Lithium Ion Battery~~	~~$7.376~~[A2]
Energy Efficiency	$0.000

~~Demand Capacity Resources – Residential~~	
~~Technology Type~~	~~Offer Review Trigger Price ($/kW-month)~~
~~Load Management~~	~~$7.559~~
~~previously installed Distributed Generation~~	~~$1.008~~
~~new Distributed Generation~~	~~based on generation technology type~~
~~Energy Efficiency~~	~~$0.000~~

Other Resources	
All other technology types	Forward Capacity Auction Starting Price

Where a new resource is composed of assets having different technology types~~ and the combination of technology types is not specified in the tables above~~[A3], the resource's Offer Review Trigger Price will be calculated in accordance with the weighted average formula in Section III.A.21.2(c).

For purposes of determining the Offer Review Trigger Price of a Demand Capacity Resource composed in whole or in part of Distributed Generation, the Distributed Generation is considered new, rather than previously installed, if (1) the Project Sponsor for the New Demand Capacity Resource has participated materially in the development, installation or funding of the Distributed Generation during the five years prior to commencement of the Capacity Commitment Period for which the resource is being qualified for participation, and (2) the Distributed Generation has not been assigned to a Demand Capacity Resource with a Capacity Supply Obligation in a prior Capacity Commitment Period.

For a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, the Offer Review Trigger Prices in the table above shall apply, based on the technology type of the External

Resource; provided that, if a New Import Capacity Resource is associated with an Elective Transmission Upgrade, it shall have an Offer Review Trigger Price of the Forward Capacity Auction Starting Price plus $0.01/kW-month.

For any other New Import Capacity Resource, the Offer Review Trigger Price shall be the Forward Capacity Auction Starting Price plus $0.01/kW-month.

III.A.21.1.2. Calculation of Offer Review Trigger Prices.

(a) The Offer Review Trigger Price for each of the technology types listed above shall be recalculated using updated data for the Capacity Commitment Period beginning on June 1, 2025 and no less often than once every three years thereafter. Where any Offer Review Trigger Price is recalculated, the Internal Market Monitor will review the results of the recalculation with stakeholders and the new Offer Review Trigger Price shall be filed with the Commission prior to the Forward Capacity Auction in which the Offer Review Trigger Price is to apply.

(b) For New Generating Capacity Resources, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is as follows. Capital costs, expected non-capacity revenues and operating costs, assumptions regarding depreciation, taxes and discount rate are input into a capital budgeting model which is used to calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Offer Review Trigger Price is set equal to the year-one capacity price output from the model. The model looks at 20 years of real-dollar cash flows discounted at a rate (Weighted Average Cost of Capital) consistent with that expected of a project whose output is under contract (i.e., a contract negotiated at arm's length between two unrelated parties).

(c) For New Demand Capacity Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above shall be the same as that used for New Generating Capacity Resources, with the following exceptions. First, the model takes account of all costs incurred by the utility and end-use customer to deploy the efficiency measure. Second, rather than energy revenues, the model recognizes end-use customer savings associated with the efficiency programs. Third, the model assumes that all costs are expensed as incurred. Fourth, the benefits realized by end-use customers are assumed to have no tax implications for the utility. Fifth, the model discounts cash flows over the Measure Life of the energy efficiency measure.

(d) For New Demand Capacity Resources other than Demand Capacity Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is the same as that used for New Generating Capacity Resources, except that the model discounts cash flows over the contract life. For Demand Capacity Resources (other than those comprised of Energy Efficiency) that are composed primarily of large commercial or industrial customers that use pre-existing equipment or strategies, incremental costs include new equipment costs and annual operating costs such as customer incentives and sales representative commissions. For Demand Capacity Resources (other than Demand Capacity Resources comprised of Energy Efficiency) primarily composed of residential or small commercial customers that do not use pre-existing equipment or strategies, incremental costs include equipment costs, customer incentives, marketing, sales, and recruitment costs, operations and maintenance costs, and software and network infrastructure costs.

(e) For years in which no full recalculation is performed pursuant to subsection (a) above, the Offer Review Trigger Prices will be adjusted as follows:

(1) For the simple cycle combustion turbine and combined cycle gas turbine technology types, ~~E~~each line item associated with capital costs that is included in the capital budgeting model will be updated to reflect changes in the Bureau of Labor Statistics Producer Price Index for Machinery and Equipment: General Purpose Machinery and Equipment (WPU114). For all other Generating Capacity Resource technology types, each line item associated with capital costs that is included in the capital budgeting model will be updated to reflect changes in the levelized cost of energy for that technology as published by Bloomberg.~~associated with the indices included in the table below:~~

~~Cost Component~~	~~Index~~
~~gas turbines~~	~~BLS-PPI "Turbines and Turbine Generator Sets"~~
~~steam turbines~~	~~BLS-PPI "Turbines and Turbine Generator Sets"~~
~~wind turbines~~	~~Bloomberg Wind Turbine Price Index~~
~~Other Equipment~~	~~BLS-PPI "General Purpose Machinery and Equipment"~~
~~construction labor~~	~~BLS "Quarterly Census of Employment and Wages" 2371 Utility System Construction Average Annual Pay:~~ ~~- Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts~~ ~~- On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine~~
~~other labor~~	~~BLS "Quarterly Census of Employment and Wages" 2211 Power Generation and Supply Average Annual Pay:~~

	~~- Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts~~ ~~- On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine~~
~~materials~~	~~BLS-PPI "Materials and Components for Construction"~~
~~electric interconnection~~	~~BLS - PPI "Electric Power Transmission, Control, and Distribution"~~
~~gas interconnection~~	~~BLS - PPI "Natural Gas Distribution: Delivered to ultimate consumers for the account of others (transportation only)"~~
~~fuel inventories~~	~~Federal Reserve Bank of St. Louis "Gross Domestic Product: Implicit Price Deflator (GDPDEF)"~~

~~(2) Each line item associated with fixed operating and maintenance costs that is included in the capital budgeting model will be associated with the indices included in the table below:~~

~~**Cost Component**~~	~~**Index**~~
~~labor, administrative and general~~	~~BLS "Quarterly Census of Employment and Wages" 2211 Power Generation and Supply Average Annual Pay:~~ ~~- Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts~~ ~~- On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine~~
~~materials and contract services~~	~~BLS-PPI "Materials and Components for Construction"~~
~~site leasing costs~~	~~Federal Reserve Bank of St. Louis "Gross Domestic Product: Implicit Price Deflator (GDPDEF)"~~

(~~3~~2) For each line item in (1) ~~and (2)~~ above, the ISO shall calculate a multiplier that is equal to the average of values published during the most recent 12 month period available at the time of making the adjustment divided by the average of the most recent 12 month period available at the time of establishing the Offer Review Trigger Prices ~~for the FCA~~ reflected in the table in Section III.A.21.1.1 ~~above~~. The value of each line item associated with capital costs ~~and fixed operating and maintenance costs included~~ in the capital budgeting model for the FCA reflected in the table in Section A.21.1.1 ~~above~~ will be adjusted by the relevant multiplier.

(~~4~~3) The energy and ancillary services offset values for gas ~~each~~ technology types in the capital budgeting model shall be adjusted by inputting to the capital budgeting model the ~~most recent~~ Henry Hub natural gas futures prices, the Algonquin Citygates Basis natural gas futures prices and the Massachusetts Hub Day-Ahead Peak ~~On-Peak~~ electricity prices, as published by ICE for the first five trading days in February, for each ~~the~~ month~~s in the Capacity Commitment Period beginning June 1~~ of the Capacity Commitment Period to which the updated value will apply~~, 2021, as published by ICE~~.

The energy and ancillary services offset values for non-gas technology types in the capital budgeting model shall be adjusted by inputting to the capital budgeting model the Massachusetts Hub Day-Ahead Peak electricity prices, as published by ICE for the first five trading days in February, for each month of the Capacity Commitment Period to which the updated value will apply.

(~~5~~4) Renewable energy credit values in the capital budgeting model shall be updated based on the first ~~most recent~~ MA Class 1 REC prices published in February for the five vintages closest to the first year of the Capacity Commitment Period associated with the relevant FCA as published by SNL Financial.

(5) The bonus tax depreciation adjustment included in the financial model for the Offer Review Trigger Prices (which is 40 percent for the Capacity Commitment Period beginning on June 1, 2025), shall be 20 percent for the Capacity Commitment Period beginning on June 1, 2026, and zero for the Capacity Commitment Period beginning on June 1, 2027 and thereafter.

(6) The investment tax credit adjustment included in the financial model for the Offer Review Trigger Prices for the photovoltaic solar ~~and combined photovoltaic solar and energy storage device – lithium ion battery~~ [A4]Generating Capacity Resource technology type~~s~~ (which is 26 percent for the Capacity Commitment Period beginning on June 1, 2025), shall be 22 percent for the Capacity Commitment Period beginning on June 1, 2026, and 10 percent for the Capacity Commitment Period beginning on June 1, 2027 and thereafter.

(~~6~~7) The capital budgeting model and the Offer Review Trigger Prices adjusted pursuant to this subsection (e) will be published on the ISO's web site.

(~~7~~8) If any of the values required for the calculations described in this subsection (e) are unavailable, then comparable values, prices or sources shall be used.

III.A.21.2. New Resource Offer Floor Prices and Offer Prices.

For every new resource participating in a Forward Capacity Auction, the Internal Market Monitor shall determine a New Resource Offer Floor Price or offer prices, as described in this Section III.A.21.2.

(a) For a Lead Market Participant with a New Capacity Resource that does not submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 or III.13.1.4.1.1.2.8, the New Resource Offer Floor Price shall be calculated as follows:

> For a New Import Capacity Resource (other than a New Import Capacity Resource that is (i) backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or (ii) associated with an Elective Transmission Upgrade) the New Resource Offer Floor Price shall be $0.00/kW-month.
>
> For a New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity Resource that is associated with an Elective Transmission Upgrade, and New Demand Capacity Resource, the New Resource Offer Floor Price shall be equal to the applicable Offer Review Trigger Price.

A resource having a New Resource Offer Floor Price higher than the Forward Capacity Auction Starting Price shall not be included in the Forward Capacity Auction.

(b) For a Lead Market Participant with a New Capacity Resource that does submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 and III.13.1.4.1.1.2.8, the resource's New Resource Offer Floor Price and offer prices in the case of a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) shall be calculated as follows:

> For a New Import Capacity Resource that is subject to the pivotal supplier test in Section III.A.23 and is found not to be associated with a pivotal supplier as determined pursuant to Section III.A.23, the resource's New Resource Offer Floor Price and offer prices shall be equal to the lower of (i) the requested offer price submitted to the ISO as described in Sections III.13.1.1.2.2.3 and III.13.1.3.5; or (ii) the price revised pursuant to Section III.13.1.3.5.7.

For any other New Capacity Resource, the Internal Market Monitor shall enter all relevant resource costs and non-capacity revenue data, as well as assumptions regarding depreciation, taxes, and discount rate into the capital budgeting model used to develop the relevant Offer Review Trigger Price and shall calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Internal Market Monitor shall compare the requested offer price to this capacity price estimate and the resource's New Resource Offer Floor Price and offer prices shall be determined as follows:

(i) The Internal Market Monitor will exclude any out-of-market revenue sources from the cash flows used to evaluate the requested offer price. Out-of-market revenues are any revenues that are: (a) not tradable throughout the New England Control Area or that are restricted to resources within a particular state or other geographic sub-region; or (b) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner. Expected revenues associated with economic development incentives that are offered broadly by state or local government and that are not expressly intended to reduce prices in the Forward Capacity Market are not considered out-of-market revenues for this purpose. In submitting its requested offer price, the Project Sponsor shall indicate whether and which project cash flows are supported by a regulated rate, charge, or other regulated cost recovery mechanism. If the project is supported by a regulated rate, charge, or other regulated cost recovery mechanism, then that rate will be replaced with the Internal Market Monitor estimate of energy revenues. Where possible, the Internal Market Monitor will use like-unit historical production, revenue, and fuel cost data. Where such information is not available (e.g., there is no resource of that type in service), the Internal Market Monitor will use a forecast provided by a credible third party source. The Internal Market Monitor will review capital costs, discount rates, depreciation and tax treatment to ensure that it is consistent with overall market conditions. Any assumptions that are clearly inconsistent with prevailing market conditions will be adjusted.

(ii) For a New Demand Capacity Resource, the resource's costs shall include all expenses, including incentive payments, equipment costs, marketing and selling and administrative and general costs incurred to acquire and/or develop the Demand Capacity Resource. Revenues shall include all non-capacity payments expected from the ISO-administered markets made for services delivered from the associated Demand Response Resource, and expected costs avoided by the associated end-use customer as a direct result of the installation or implementation of the associated Asset(s).

(iii) For a New Capacity Resource that has achieved commercial operation prior to the New Capacity Qualification Deadline for the Forward Capacity Auction in which it seeks to participate, the relevant capital costs to be entered into the capital budgeting model will be the undepreciated original capital costs adjusted for inflation. For any such resource, the prevailing market conditions will be those that were in place at the time of the decision to construct the resource.

(iv) Sufficient documentation and information must be included in the resource's qualification package to allow the Internal Market Monitor to make the determinations described in this subsection (b). Such documentation should include all relevant financial estimates and cost projections for the project, including the project's pro-forma financing support data. For a New Import Capacity Resource, such documentation should also include the expected costs of purchasing power outside the New England Control Area (including transaction costs and supported by forward power price index values or a power price forecast for the applicable Capacity Commitment Period), expected transmission costs outside the New England Control Area, and expected transmission costs associated with importing to the New England Control Area, and may also include reasonable opportunity costs and risk adjustments. For a new capacity resource that has achieved commercial operation prior to the New Capacity Qualification Deadline, such documentation should also include all relevant financial data of actual incurred capital costs, actual operating costs, and actual revenues since the date of commercial operation. If the supporting documentation and information required by this subsection (b) is deficient, the Internal Market Monitor, at its sole discretion, may consult with the Project Sponsor to gather further information as necessary to complete its analysis. If after consultation, the Project Sponsor does not provide sufficient documentation and information for the Internal Market Monitor to complete its analysis, then the resource's New Resource Offer Floor Price shall be equal to the Offer Review Trigger Price.

(v) If the Internal Market Monitor determines that the requested offer prices are consistent with the Internal Market Monitor's capacity price estimate, then the resource's New Resource Offer Floor Price shall be equal to the requested offer price, subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vi) If the Internal Market Monitor determines that the requested offer prices are not consistent with the Internal Market Monitor's capacity price estimate, then the resource's offer prices shall be set to a level that is consistent with the capacity price estimate, as determined by the Internal Market Monitor. Any such determination will be explained in the resource's qualification determination notification and will be filed with the Commission as part of the filing described in Section III.13.8.1(c), subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vii) For New Import Capacity Resources that have been found to be associated with a pivotal supplier as determined pursuant to Section III.A.23, if the supplier elects to revise the requested offer prices pursuant to Section III.13.1.3.5.7 to values that are below the Internal Market Monitor's capacity price estimate established pursuant to subsection (v) or (vi), then the resource's offer prices shall be equal to the revised offer prices.

(c) For a new capacity resource composed of assets having different technology types ~~and the combination of the technology types is not specified in the tables in Section III.A.21.1.1,~~ [A5]the Offer Review Trigger Price shall be the weighted average of the Offer Review Trigger Prices of the asset technology types of the assets that comprise the resource, based on the expected capacity contribution from each asset technology type. Sufficient documentation must be included in the resource's qualification package to permit the Internal Market Monitor to determine the weighted average Offer Review Trigger Price.

III.A.22. [Reserved.]

III.A.23. Pivotal Supplier Test for Existing Capacity Resources and New Import Capacity Resources in the Forward Capacity Market.

III.A.23.1. Pivotal Supplier Test.

The pivotal supplier test is performed prior to the commencement of the Forward Capacity Auction at the system level and for each import-constrained Capacity Zone.

An Existing Capacity Resource or New Import Capacity Resource is associated with a pivotal supplier if, after removing all the supplier's FCA Qualified Capacity, the ability to meet the relevant requirement is less than the requirement. Only those New Import Capacity Resources that are not (i) backed by a single new External Resource and associated with an investment in transmission that increases New England's import capability, or (ii) associated with an Elective Transmission Upgrade, are subject to the pivotal supplier test.

ISO new england

memo

To: NEPOOL Participants Committee

From: Internal Market Monitor

Date: March 3, 2021

Subject: Follow Up on Retirement De-List and Permanent De-List Bids and Test Prices Conditional Upon the Regulatory Outcome of the Offer Review Trigger Price Jump Ball Proceeding

In a memo dated February 22, 2021, the Internal Market Monitor (IMM) provided guidance to Market Participants on submitting Retirement De-List Bids, Permanent De-List Bids and substitution auction test prices for the sixteenth Forward Capacity Auction (FCA 16) in light of the expected timing of a ruling by the Federal Energy Regulatory Commission (FERC) on Offer Review Trigger Price (ORTP) values in May 2021. Under Section 205 of the Federal Power Act, FERC's expected ruling on the ISO's proposal for recalculating ORTP values will include a "jump ball" alternate proposal of ORTP values from NEPOOL. Depending on which ORTP values are accepted by FERC, this ruling (i) could directly and materially impact the formulation of delist bids or offers by Market Participants, and yet (ii) will not be available prior to submission of the delist bids or offers that are due on March 12, 2021.

In response to inquiries from Market Participants, the IMM now clarifies how a Market Participant may submit Retirement De-List Bids, Permanent De-List Bids and test prices for FCA 16 by the submission deadline that are conditional upon the outcome of the ORTP jump ball regulatory proceeding. While Market Participants must commit to a delist bid submission by the deadline, Market Participants may submit a Retirement De-List Bid, Permanent De-List Bid and/or test price that is effective under one or more scenarios described below and may chose specific scenarios where no delist bid is to be applied.

The IMM assumes the following three potential regulatory outcomes to the jump ball ORTP filing:

1. Baseline case assumption: FERC approves the ISO proposed ORTP values;

2. Alternative case assumption: FERC approves the NEPOOL proposed ORTP values;

3. Rejection/Other assumption: FERC rejects both the Baseline and Alternative cases above and/or approves a combination of other ORTP values.

In their submissions, Market Participant will be asked to specify for which outcome(s) the submitted Retirement De-List Bid, Permanent De-List Bid or substitution auction test price is applicable.

Example 1: If a resource would like to submit a Retirement De-List Bid under all three potential outcomes, the resource would check all boxes on the "Retirement De-List Bid" row.

Bid Type	Baseline case assumption (check box if applicable)	Alternative case assumption (check box if applicable)	Rejection/Other assumption (check box if applicable)
Retirement De-List Bid	☒	☒	☒
Permanent De-List Bid	☐	☐	☐
Substitution Auction Test Price	☐	☐	☐

Example 2: If a resource would like to submit a Permanent De-List Bid, but only in the Alternative case, then the resource would check the box applicable to the Alternative case on the Permanent De-List Bid row.

Bid Type	Baseline case assumption (check box if applicable)	Alternative case assumption (check box if applicable)	Rejection/Other assumption (check box if applicable)
Retirement De-List Bid	☐	☐	☐
Permanent De-List Bid	☐	☒	☐
Substitution Auction Test Price	☐	☐	☐

Conceivably, some Market Participants may wish to submit a Retirement De-List Bid, Permanent De-List Bid or test price under the Rejection/Other assumption (i.e., if FERC does not accept the Baseline case or Alternate case assumptions) but only if certain ORTP values (including changes to indexing) are accepted by FERC under this Rejection/Other assumption. In such case, the Market Participant should specify in its submission that it wishes to submit the Retirement De-List, Permanent De-List Bid or test price under the Rejection/Other assumption, but if and only if the specified assumed values are approved by FERC. Therefore, each Market Participant must state clearly and specifically in its submission the regulatory outcomes (i.e., assumed values) upon which its Retirement De-List Bid, Permanent De-List Bid or test price is contingent.

In short, when submitting a complete and timely Retirement De-List Bid, Permanent De-List Bid or test price, Market Participants must specify whether and to what extent such de-list bid or test price is conditional upon the outcome of the FERC ORTP jump ball ruling and related approval of ORTP values.

A form is provided for your convenience on the next page. For pre-submission consultation with the IMM, please contact intmmufcm@iso-ne.com.

Regulatory Outcome Form – Indicate scenario(s) for which the submission is applicable

One per resource.

Lead Market Participant Name:

Resource Name:

Resource ID:

Bid Type	Baseline case assumption (check box if applicable)	Alternative case assumption (check box if applicable)	Rejection/Other assumption (check box if applicable)
Retirement De-List Bid	☐	☐	☐
Permanent De-List Bid	☐	☐	☐
Substitution Auction Test Price	☐	☐	☐

Participant Comments / Explanation:

For pre-submission consultation with the IMM, please contact intmmufcm@iso-ne.com.

memo

To: NEPOOL Participants Committee

From: ISO New England

Date: March 4, 2021

Subject: ISO's plan to address the CONE filing deficiency notice

The ISO has been evaluating the deficiency notice on the CONE, Net CONE, and Capacity Performance Payment Rate (PPR) update for FCA 16 that the FERC issued this week on March 1st.[1] The scope of the FERC's information requests is limited, and the ISO plans to provide answers shortly, as described below.

The deficiency notice arrived on the anticipated Order date and the eve of the requested effective date of March 2nd. The ISO understands that the resulting delay of the CONE Order may cause uncertainty for participants about how the FCA 16 qualification process will proceed in the meantime.

To help address this uncertainty, the ISO is providing this memorandum to outline its plan for responding to the deficiency notice and carrying out the FCA 16 qualification process until we receive an Order.

FCA 16 Qualification Activities

The current schedule of qualification activities for FCA 16 will continue as planned. To administer these activities, the ISO will apply the FCA 16 CONE, Net CONE, and PPR values as filed on December 31, 2020.[2]

The immediately upcoming activities are the Dynamic De-List Bid Threshold (DDBT) calculation on this Friday (March 5th) and retirement and permanent de-list bids submittal deadline on next Friday (March 12th). Participants are advised to adhere to the filed FCA 16 CONE values and published DDBT value when making their elections and developing supporting assumptions for their bids.[3]

Plan for Deficiency Response

The ISO plans to file its response to the deficiency notice on or around next Thursday (March 11th). The ISO understands that the FERC is undoubtedly aware that an extended delay of the CONE Order could

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[1] *ISO New England Inc.*, Letter informing ISO New England Inc. that the 12/31/2020 filing is deficient and requesting additional information within 30 days, Docket No. ER21-787-000 (issued March 1, 2021).

[2] *ISO New England Inc.*, Updates to CONE, Net CONE, and Capacity Performance Payment Rate, Docket No. ER21-787-000 (filed December 31, 2020).

[3] We recognize the uncertainty regarding the Offer Review Trigger Prices for the FCA 16 cycle; the Internal Market Monitor has addressed in a separate memorandum the manner in which participants can account for this uncertainty as relevant to the retirement and permanent de-list bid submittal process.

affect the FCA schedule. Accordingly, and in light of the limited nature of the deficiency requests, the ISO will request expedited review, with the objective of receiving an Order on the FCA 16 CONE filing by mid-April. If FERC chooses to use the full 60 days available to it, then the Order date will be in mid-May.

With the deficiency response, the ISO will explain the above-detailed plan to apply the CONE, Net CONE, and PPR values filed on December 31st for purposes of continuing the FCA 16 qualification activities. In addition, the ISO will provide the FERC with an explanation of steps that, if employed, could maximize the potential to preserve the FCA 16 schedule in the event FERC does not accept the FCA 16 CONE values as filed by the ISO. The outline of this explanation will entail:

- Requesting that FERC provide in a rejection Order (1) clear explanations of the inputs or assumptions for the CONE values that the FERC did not accept and why, and (2) an expedited compliance obligation to re-file updated FCA 16 CONE values to address the identified issues. This guidance would allow the ISO to respond quickly to a rejection and improve the chances of preventing a delay in the administration of FCA 16.

- Explaining that, in such an event, the ISO will need to make necessary adjustments to the FCA 16 qualification process, including possible adjustments to deadlines to permit participants to resubmit material reflecting the re-filed CONE values and to permit the ISO the time necessary to act upon such (re)submittals to complete the auction qualification process. The exact details of any such plan cannot be developed until (and unless) a FERC Order rejecting the FCA 16 CONE values is issued. In the upcoming deficiency response, the ISO will commit to developing and filing any such required plan when it would re-file updated CONE values in response to a rejection. To be clear, the ISO would endeavor to make every reasonable accommodation to provide participants the necessary flexibility to respond to the re-filed FCA 16 CONE values while also seeking to preserve the FCA16 auction schedule.

Stakeholder questions and observations on this plan to manage the FCA 16 qualification process are welcomed to help ensure participants feel informed about how this process will work.

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of March 3, 2021

The following activity, as more fully described in the attached litigation report, has occurred since the report dated February 2, 2021 ("last Report") was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

COVID-19

No Activity to Report

I. Complaints/Section 206 Proceedings

*	2	Green Development DAF Charges Complaint Against National Grid (ER21-47)	Feb 10 Feb 19-Mar 2 Mar 2	Green Development files Complaint Avangrid, Energy Development Partners, NY TOs intervene National Grid answers Complaint; SEIA, Dry Bridge Solar submit comments
	5	RNS/LNS Rates and Rate Protocols Settlement Agreement II (ER20-2054)	Feb 24	FERC accepts TOs' compliance filing establishing effective dates for the ISO-NE Tariff records that implement Settlement Agreement II

II. Rate, ICR, FCA, Cost Recovery Filings

*	8	FCA15 Results Filing (ER21-1226)	Feb 26 Mar 1-Mar 2	ISO-NE files FCA15 results; comment date ***Apr 12, 2021*** NESCOE, Public Citizen intervene
*	8	Essential Power Newington CIP IROL (Schedule 17) Cost Recovery Filing (ER21-1171)	Feb 18 Feb 22	EP Newington requests FERC acceptance of a proposed rate schedule to allow EP Newington to begin the recovery period for certain CIP-IROL Costs under ISO-NE Tariff Schedule 17; comment date ***Mar 11, 2021*** NESCOE intervenes
	9	Dynegy CIP IROL (Schedule 17) Cost Recovery Filing (ER21-774)	Feb 26	FERC accepts CIP IROL Cost Recovery Period Filing, eff. Mar 1, 2021
	10	Mystic 8/9 Cost of Service Agreement (ER18-1639)	Feb 25	Mystic submits 3rd compliance filing; comment date ***Mar 18, 2021***

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

	11	Elimination of Price Lock and Zero-Price Offer Rule for New Entrants Starting in FCA16 (ER21-1010)	Feb 3-23 Feb 9, 23	BSW ProjectCo, Calpine, Eversource, National Grid, NESCOE, NRG intervene NEPOOL, NEPGA submit comments supporting revisions
	12	EER Exemption from PFP Settlement (ER21-943)	Feb 4-16 Feb 16 Mar 3	Calpine, Eversource, MA AG, National Grid, NRG, Vistra intervene NEPOOL, IMM, LS Power companies, NEPGA file comments supporting exemption; AEE protests revisions ISO-NE answers AEE protest
	12	Updated CONE, Net Cone and PPR Values (eff. FCA16) (ER21-787)	Feb 12 Feb 16-17 Mar 1	ISO-NE answers Jan 21 protests EPSA, NEPGA and CPV Towantic answer ISO-NE's Feb 12 answer FERC issues deficiency letter; ISO-NE responses due ***Mar 31, 2021*** (submission of responses will re-set the deadline for FERC action)
	13	New DDBT Methodology (ER21-782)	Mar 1	FERC accepts new methodology, eff. Mar 2, 2021
	13	EER FCM Qualification Modifications (ER21-640)	Feb 11	FERC accepts modifications, eff. Feb 12, 2021

	14	*Order 841* Compliance Filings (Electric Storage in RTO/ISO Markets) (ER19-470)	Feb 12	FERC accepts Dec 7 *Order 841* Further Compliance Filing, eff. Mar 1, 2021 (other than revisions specific to the Day-Ahead Energy Market which will be eff. Jan 1, 2026)
	14	CASPR (ER18-619)	Feb 18	FERC rejects, as procedurally barred, the Sierra Club/NRDC/CLF request for rehearing of the Nov 19 *CASPR Allegheny Order*

V. OATT Amendments / TOAs / Coordination Agreements

No Activity to Report

V. Financial Assurance/Billing Policy Amendments

	15	FAP Info Disclosure/KYC Requirements (ER21-816)	Feb 23	ISO-NE files an amendment that re-formats certain pages (without change to any text) so that the footnotes are visible in the eTariff system
			Mar 3	FERC accepts filing, eff. Mar 9, 2021; Market Participants must submit new Info Disclosure forms by ***Apr 30, 2021***

VI. Schedule 20/21/22/23 Changes

*	15	Schedule 20A NEP-Vitol Phase I/II HVDC-TF Service Agreement (ER21-1180)	Feb 19	National Grid files a new Phase I/II HVDC-TF Service Agreement between NEP and Vitol; comment date ***Mar 12, 2021***
			Mar 1	Vitol intervenes

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

*	17	Capital Projects Report - 2020 Q4 (ER21-1109)	Feb 12	ISO-NE files Q4 Report
			Feb 17	NEPOOL intervenes and files comments supporting Q4 Report
*	17	Interconnection Study Metrics Processing Time Exceedance Report Q4 2020 (ER19-1951)	Feb 16	ISO-NE files required quarterly report
*	18	IMM Quarterly Markets Reports - 2020 Fall (ZZ21-4)	Feb 5	IMM files Fall 2020 Report

IX. Membership Filings

*	18	March 2021 Membership Filing (ER21-1228)	Feb 26	***Membership:*** Trafigura Trading. ***Terminations:*** Axon Energy; Springfield Power; ***Name Change***: Titan Gas LLC d/b/a CleanSky Energy; comment date ***Mar 19, 2021***
	18	January 2021 Membership Filing (ER21-761)	Feb 25	FERC accepts memberships of the following Supplier Sector members: Cassadaga Wind; Centrica Business Solutions Optimize; Pilot Power Group, LLC; and SmartestEnergy US; and the termination of the Participant status of Wheelabrator Bridgeport, LP

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

	19	NERC Annual Report on FFT & Compliance Exception Programs (RC11-6-011)	Feb 19	FERC accepts NERC's annual report on FFT and Compliance Exception programs
*	20	Revised Reliability Standard: FAC-008-5 (RD21-4)	Feb 19	NERC files FAC-008-5 to remove Requirement R.7; comment date ***Mar 22, 2021***
	20	Revised Reliability Standard: CIP-002-6 (RM20-17)	Feb 5	NERC withdraws proposed CIP-002-6

XI. Misc. - of Regional Interest

*	22	203 Application: Exelon Generation (EC21-57)	Feb 25 Feb 26-27	ExGen files application; comment date ***Mar 18, 2021*** PJM, PJM IMM, Public Citizen intervene
	23	LGIA: NSTAR / MMWEC (Stony Brook) (ER21-777)	Feb 26	FERC accepts LGIA, eff. Dec 31, 2020
	23	LGIA: CMP / ReEnergy Stratton (ER21-769)	Feb 19	FERC accepts LGIA, eff. Dec 21, 2020
	23	Interim Distribution Wheeling Agreement: Unitil / Briar Hydro (ER21-759)	Feb 22	FERC accepts Agreement, eff. Dec 28, 2020
	24	SGIA: CL&P / ECRRA (ER21-651)	Feb 10	FERC accepts SGIA, eff. Dec 15, 2020
	24	*Orders 864/864-A* (Public Util. Trans. ADIT Rate Changes): New England Compliance Filings (various)	Feb 11 Feb 12 Feb 16	*ER20-2133 (Versant Power).* FERC issues deficiency letter; response date ***Mar 15, 2021*** *ER21-1130 (TOs).* TOs supplement their Jul 30 compliance filing *ER21-1154 (FG&E).* FG&E submits changes to Sched. 21-FG&E

XII. Misc. - Administrative & Rulemaking Proceedings

*	25	Electrification & the Grid of the Future Tech Conf (Apr 29, 2021) (AD21-12)	Mar 2	FERC issues notice of Apr 29, 2021 tech conf; panelist self-nominations due ***Mar 19, 2021***
*	25	Resource Adequacy - Modernizing Electricity Mkt Design (AD21-10)	Feb 18	FERC issues notice of Mar 23, 2021 tech conf on resource adequacy in the evolving electricity sector
*	25	The Office of Public Participation (AD21-9)	Feb 22	FERC issues notice of Apr 16, 2021 workshop; panelist self-nominations due ***Mar 10, 2021***
	26	ISO/RTO Credit Principles and Practices (AD21-6)	Feb 10 Feb 25-26	FERC issues supplemental notice of tech conf Technical conference held
	26	Offshore Wind Integration in RTOs/ISOs Tech Conf (Oct 27, 2020) (AD20-18)	Feb 9	Advanced Power Alliance files comments requesting that the FERC issue a notice providing an opportunity for interested persons to submit post-conference comments
	28	Grid Resilience in RTO/ISOs (AD18-7)	Feb 18	FERC terminates proceeding, finding concerns are best addressed on a case-by-case and region-by-region basis
	28	NOPR: Cybersecurity Incentives (RM21-3)	Feb 9 Feb 16	aDolus Inc., Fortress Info. Security, GMO GlobalSign Inc., Ion Channel, ReFirm Labs & Reliable Energy Analytics file joint comments George Cotter, Esq. files comments; ***comment date Apr 6, 2021***
	30	*Order 2222*: DER Participation in RTO/ISO Markets (RM18-9)	Feb 17 Feb 18 Feb 26	MISO requests extension of time to comply SPP requests extension of time to comply PJM requests extension of time to comply
	31	*Order 860/860-A*: Data Collection for Analytics & Surveillance and MBR Purposes (RM16-17)	Feb 25	FERC issues notice of ***Mar 25, 2021*** tech workshop to discuss the functionality and features of the MBR Database
	34	NOI: Certification of New Interstate Natural Gas Facilities (PL18-1)	Feb 18	FERC issues new NOI (2021 NOI) in which it seeks new information and additional stakeholder perspectives to help it explore whether it should revise its approach under the currently effective policy statement on the certification of new natural gas transportation facilities; comment date ***Apr 26, 2021***

XIII. Natural Gas Proceedings

**	35	Atlantic Bridge Project (CP16-9)	Feb 18	FERC, expressing concerns regarding operation of the project, establishes briefing procedures; Initial briefs due ***April 5, 2021***; reply briefs, ***May 5, 2021***

XIV. State Proceedings & Federal Legislative Proceedings

39	New England States' Vision Statement / On-Line Technical Forums	Feb 25	Governance Reform Technical Forum held; comments due Mar 26

XV. Federal Courts

40	Exelon PP-10 Complaint (20-1509)	Feb 16 Feb 18	Mystic moves to voluntarily dismiss Petition for Review Clerk issues order granting Mystic's request and issues mandate to the FERC, ending this proceeding
40	ISO-NE Implementation of Order 1000 Exemptions for Immediate Need Reliability Projects (20-1422)	Mar 2	Court issues an amended briefing schedule to apply in this case
41	CIP IROL Cost Recovery Rules (20-1389)	Mar 1	Cogentrix/Vistra file Petitioners' Brief
41	Mystic 8/9 Cost of Service Agreement (20-1343; 20-1361, 20-1362; 20-1365, 20-1368) (consolidated)	Feb 17 Feb 24 Feb 26	Court consolidates 21-1067 (NESCOE) with Case 20-1343 Court consolidates 21-1070 (CT Parties) with Case 20-1343 FERC files motion indicating that this case can return to the Court's active docket and its expectation to file a proposed briefing schedule
41	CASPR (20-1333, 20-1331) (consolidated)	Feb 18 Feb 26	NEPOOL moves for leave to intervene in this case Parties submit proposed briefing format; FERC requests 60 days between the Petitioners' opening brief and its brief in response
42	*Opinion 531-A* Compliance Filing Undo (20-1329)	Feb 11	Court issues order holding case in abeyance pending further order of the Court and directing the parties to file motions to govern future proceedings in this case by ***Apr 26, 2021***
43	ISO-NE's Inventoried Energy Program (Chapter 2B) Proposal (19-1224) (consol.)	Feb 9 Feb 16 Feb 24	FERC files Respondent Brief ISO-NE and NEPGA file Intervenor for Respondent Briefs FERC files an amended certified index to the record
43	Order 872 (20-72788) (consol.)	Feb 8	Court grants motion to consolidate and motion to continue to hold petitions in abeyance; directs petitioners to file a status report on or before ***Apr 9, 2021***
44	Opinion 569/569-A: FERC's Base ROE Methodology (16-1325) (consol.)	Feb 8	Statements of issues filed

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: March 3, 2021

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

We have summarized below the status of key ongoing proceedings relating to NEPOOL matters before the Federal Energy Regulatory Commission ("FERC"),[1] state regulatory commissions, and the Federal Courts and legislatures through March 3, 2021. 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 remains 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)**

On January 22, 2021, the wavier of FERC regulations that require that filings with the FERC be notarized or supported by sworn declarations was further ***extended through July 30, 2021***.[5] The January 25 notice extended the waiver first noticed in May[6] and extended on August 20, 2020.[7] 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.[8]

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

On January 25, 2021, the extension of the blanket waivers of ISO/RTO Tariff *in-person*[9] meeting and notarization requirements was further ***extended through July 30, 2021***.[10] The January 25 order extended the blanket waivers first granted in the FERC's April 2, 2020 order and extended in an August 20, 2020 order.[11]

I. Complaints/Section 206 Proceedings

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

On February 10, 2021, Green Development, LLC ("Green Development") filed a Complaint against New England Power Company and Narragansett Electric Company (together, "National Grid" or "Grid") requesting a finding that Grid's assessment of Direct Assignment Facility ("DAF") charges for Green Development's projects is unauthorized under the ISO-NE Tariff. Summarizing at highest level, Green Development asserts that the upgrades associated with the interconnection of its distribution-level, sate jurisdictional projects are not DAF as defined in the ISO-NE Tariff. Grid's answer, as well as comments and interventions with respect to the Green Development DAF Complaint were due March 2, 2021. Grid filed its answer on March 2. Solar Energy Industries Association ("SEIA") and Dry Bridge Solar submitted comments supporting the Complaint. Doc-less interventions were filed by Avangrid, Energy Development Partners and New York Transmission Owners ("NY TOs"). This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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[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 (Jan. 25, 2021).

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

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

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

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

[10] *Temporary Action to Facilitate Social Distancing*, 174 FERC ¶ 61,047 (Jan. 25, 2021).

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

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

Pending before the FERC is NEPGA's December 11, 2020 complaint against ISO-NE. The Complaint alleged that ISO-NE violated its Tariff and the filed-rate doctrine by recalculating and reviewing with NEPOOL a Net CONE value methodology demonstrably inconsistent with the Tariff and prior practice. NEPGA sought an order directing ISO-NE to recalculate, review with NEPOOL stakeholders, and file with the FERC a Net CONE value consistent with the existing Tariff definition. Should its requested relief be granted, NEPGA asked the FERC to find unjust and unreasonable the Net CONE value for FCAs 16-18 (filed on December 31, *see* ER21-787 in Section III below) and, should there not be sufficient time to allow for completion of stakeholder review before the beginning of the FCA16 calendar (March 2021), NEPGA asked that ISO-NE be directed to apply the Tariff-defined annual adjustment factors to the FCA15 Net CONE value to be used for the FCA16 Net CONE value.

ISO-NE's answer, comments and interventions with respect to the Net CONE Complaint were due December 31, 2020. In its answer, ***ISO-NE*** explained why it acted legally and consistent with its Tariff, and requested a FERC order summarily dismissing or denying NEPGA's Complaint. ***NEPOOL*** filed comments explaining why the Complaint was premature and should be rejected so that NEPGA's arguments could be properly addressed in response to ISO-NE's filing of its proposed updates to CONE, Net CONE and the PPR values. NEPOOL's comments, alternatively, suggested that the Complaint proceeding be held in abeyance pending the outcome of ISO-NE's December 31 Updated CONE, Net CONE and PPR Values filing. Protests were also filed by ***NESCOE***, ***NECOS/ENE***[12] and ***CT State Agencies***.[13] ***EPSA*** filed comments supporting NEPGA's Complaint. Doc-less interventions only were filed by Avangrid, Calpine, Dominion, Eversource, FirstLight, LS Power, MA AG, MMWEC, National Grid, NHEC, NRG, MA DPU, RI PUC, and Public Citizen. On January 8, 2021, NEPGA answered ISO-NE's Answer and the comments and protests filed in response to its Complaint. ISO-NE answered NEPGA's answer on January 25, 2021. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

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

The October 13, 2020 complaint filed by NECEC Transmission LLC ("NECEC") and Avangrid Inc. (together, "Avangrid") against NextEra[14] remains pending. As previously reported, the Complaint requested FERC action "to stop NextEra from unlawfully interfering with the interconnection of the New England Clean Energy Connect transmission project ("NECEC Project")." The Complaint sought, among other things, an initial, expedited order that would grant certain relief[15] and direct NextEra to immediately commence engineering, design, planning and procurement activities that are necessary for NextEra to construct the generator owned transmission upgrades during Seabrook Station's Planned 2021 Outage.

[12] "NECOS/ENE" are: Belmont Municipal Light Department, Block Island Utility District, Braintree Electric Light Department, Georgetown Municipal Light Department, Groveland Electric Light Department, Hingham Municipal Lighting Plant, Littleton Electric Light Department, Merrimac Municipal Light Department, Middleborough Gas & Electric Department, Middleton Electric Light Department, North Attleborough Electric Department, Norwood Light & Broadband Department, Reading Municipal Light Department, Rowley Municipal Lighting Plant, Stowe Electric Department, Taunton Municipal Lighting Plant, and Wallingford Department of Public Utilities Electric Division (collectively, "NECOS"); and Energy New England, LLC ("ENE").

[13] "CT Agencies" are: the Connecticut Department of Energy and Environmental Protection ("CT DEEP"), William Tong, Attorney General for the State of Connecticut ("CT AG"), the Connecticut Public Utilities Regulatory Authority ("CT PURA") and the Connecticut Office of Consumer Counsel ("CT OCC")

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

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

Comments on the Complaint were due on or before November 2, 2020. On November 2, NextEra submitted an answer to the Complaint (requesting the FERC dismiss or deny the Complaint) and National Grid filed comments. Doc-less interventions were filed by Dominion, Eversource, Calpine, Exelon, HQ US, MA AG, MMWEC National Grid, NESCOE, NRG, and Public Citizen. On November 17, Avangrid submitted an answer to NextEra's November 2 Answer. On November 30, NextEra answered Avangrid's November 17 answer ("supplemental answer"), repeating its request that the FERC dismiss or deny the Complaint. Avangrid answered the November 30 supplemental answer on December 7, 2020. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

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

Comments on Seabrook's Petition were due on or before November 4, 2020, and were filed by Eversource, MMWEC, and NEPGA. Avangrid and NECEC Transmission ("Avangrid") protested the Declaratory Order. Doc-less interventions were filed by Avangrid, Dominion, Eversource, Calpine, Exelon, HQ US, National Grid, NESCOE, NRG, and Public Citizen. On November 19, NextEra answered Avangrid's protest. On December 4, Avangrid answered NextEra's November 19 answer. This matter is also pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

New England Generators'[16] August 25, 2020 complaint against Exelon[17] remains pending. As previously reported, the Complaint requested that, if and to the extent the FERC does not grant all relief requested by the New England Generators in its August 27, 2020 request for clarification and/or rehearing of the *July 17 Orders* in the Mystic 8/9 Cost of Service Agreement ("COS Agreement") proceeding (*see* ER18-1639 below), the FERC should find that the new information about Exelon's two new queue positions and Exelon's intention to continue to operate Everett beyond the term of the Mystic Agreement makes the existing rate in the Mystic Agreement unjust and unreasonable. New England Generators further requested that the FERC change the Mystic Agreement to: (i) apply the clawback mechanisms to Exelon's two new interconnection queue positions (to prevent Exelon from using interconnection queue positions for "new" or "repowered" units to skirt restrictions imposed on Mystic's recovery of costs pursuant to the COS Agreement); (ii) delete or give no meaning to the words "that were expensed" (in order to prevent Exelon from shielding costs paid for by captive ratepayers from the application of the COS Agreement's clawback provision); and (iii) require that Mystic return any of the undepreciated Everett

[16] "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.

[17] 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.").

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[18] and Connecticut Parties.[19] On September 28, NEPGA answer Exelon's answer. Calpine, ENE, Eversource, Massachusetts Attorney General ("MA AG") National Grid, and Public Citizen filed doc-less interventions. The Complaint, as well as all of the pleadings in response, remain pending before the FERC. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **RNS/LNS Rates and Rate Protocols Settlement Agreement II Compliance Filing (ER20-2054)**

On February 24, 2021, the FERC accepted[20] the TO's January 27, 2021 compliance filing that established the following effective dates for the ISO-NE Tariff records that implement the Settlement approved by the FERC ("Settlement Agreement II"):[21]

- ***Jun 15, 2021*** Interim Formula Rate Protocols (Appendix C to Attachment F)
- ***Jan 1, 2022*** Attachment F (other than Appendix C); Section II.25, Schedule 8, Schedule 9 and each of the OATT Schedule 21s
- ***Jun 15, 2023*** Final Formula Rate Protocols (Appendix C to Attachment F)

Unless the February 24 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).

- **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,[22] 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*).[23] However, the FERC's orders were challenged, and in *Emera Maine,*[24] the DC Circuit vacated the FERC's prior orders, and remanded the case for further proceedings consistent with its

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

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

[20] *ISO New England Inc., et al.*, Docket No. ER20-2054-001 (Feb. 24, 2021).

[21] *ISO New England Inc., et al.*, 173 FERC ¶ 61,270 (Dec. 28, 2020).

[22] 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*")).

[23] *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*").

[24] *Emera Maine v. FERC*, 854 F.3d 9 (D.C. Cir. 2017) ("*Emera Maine*"). *Emera Maine* vacated the FERC's prior orders in the Base ROE Complaint I proceeding, and remanded the case for further proceedings consistent with its order. The Court agreed with both the TOs (that the FERC did not meet the Section 206 obligation to first find the existing rate unlawful before setting the new rate) and "Customers" (that the 10.57% ROE was not based on reasoned decision-making, and was a departure from past precedent of setting the ROE at the midpoint of the zone of reasonableness).

order. The FERC's determinations in *Opinion 531* are thus no longer precedential, though the FERC remains free to re-adopt those determinations on remand as long as it provides a reasoned basis for doing so.

- ***Base ROE Complaints II & III (EL13-33 and EL14-86) (consolidated)***. The second (EL13-33)[25] and third (EL14-86)[26] 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.[27] 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[28] also went to hearing before an ALJ, Judge Glazer, who issued his initial decision on March 27, 2017.[29] 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.[30] 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.[31] 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*[32] (EL14-12; EL15-45) in

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[25] 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%.

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

[27] *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*").

[28] 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.

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

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

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

[32] *Ass'n of Buss. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569-A, 171 FERC ¶ 61,154 (2020) ("*Opinion 569-A*"). The refinements to the FERC's ROE methodology included: (i) the use of the Risk Premium model instead of only relying on the DCF model and CAPM under both prongs of FPA Section 206; (ii) adjusting the relative weighting of long- and short-term growth rates, increasing the weight for the short-term growth rate to 80% and reducing to 20% the weight given to the long-term growth rate in

Section XI below). The FERC established a paper hearing on how its proposed methodology should apply to the four pending ROE proceedings.[33]

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%.[34] 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[35] for an extension of time to submit briefs, the latest date for filing initial and reply briefs was extended to January 11 and March 8, 2019, respectively. On January 11, initial briefs were filed by EMCOS, Complainant-Aligned Parties, TOs, EEI, Louisiana PSC, Southern California Edison, and AEP. As part of their initial briefs, each of the Louisiana PSC, SEC and AEP also moved to intervene out-of-time. Those interventions were opposed by the TOs on January 24, 2019. The Louisiana PSC answered

the two-step DCF model; (iii) modifying the high-end outlier test to treat any proxy company as high-end outlier if its cost of equity estimated under the model in question is more than 200% of the median result of all the potential proxy group members in that model before any high- or low-end outlier test is applied, subject to a natural break analysis. This is a shift from the 150% threshold applied in *Opinion 569*; and (iv) calculating the zone of reasonableness in equal thirds, instead of using the quartile approach that was applied in *Opinion 569*.

[33] *Id.* at P 19.

[34] *Id.* at P 59.

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

the TOs' January 24 motion on February 12. Reply briefs were due March 8, 2019 and were submitted by the TOs, Complainant-Aligned Parties, EMCOS, FERC Trial Staff.

TOs Request to Re-Open Record and file Supplemental Paper Hearing Brief. On December 26, 2019, the TOs filed a Supplemental Brief that addresses the consequences of the November 21 *MISO ROE Order*[36] and requested that the FERC re-open the record to permit that additional testimony on the impacts of the *MISO ROE Order*'s changes. On January 21, 2020, EMCOS and CAPs opposed the TOs' request and brief.

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

II. Rate, ICR, FCA, Cost Recovery Filings

- **FCA15 Results Filing (ER20-1226)**

On February 26, ISO-NE filed the results of the fifteenth FCA ("FCA15") held February 8, 2021. ISO-NE reported the following highlights:

- ♦ FCA15 Capacity Zones were the Southeastern New England ("SENE") Capacity Zone (the Northeastern Massachusetts ("NEMA")/Boston, Southeastern Massachusetts, and Rhode Island Load Zones), the Northern New England ("NNE") Capacity Zone (the Maine, New Hampshire and Vermont Load Zones), the Maine Capacity Zone (the Maine Load Zone) and the Rest-of-Pool ("ROP") Capacity Zone (the Connecticut and Western/Central Massachusetts Load Zones). NNE was modeled as an export-constrained Capacity Zone. The Maine Load Zone was modeled as a separate nested export-constrained Capacity Zone within NNE.
- ♦ FCA15 commenced with a starting price of $13.932/kW-mo. and concluded for all Capacity Zones after five rounds.
- ♦ Capacity Clearing Prices were as follows (prices expressed per kw-mo.): SENE - $3.980; NNE and Maine - $2.477; ROP - $2.611; imports over the NY AC Ties (684 MW) and the Phase I/II HQ Excess external interface (517 MW) - $2.611; imports over Highgate (60 MW) and New Brunswick (226 MW) - $2.477.
- ♦ There were no active demand bids for the substitution auction and, accordingly, the substitution auction was not conducted.
- ♦ No resources cleared as Conditional Qualified New Generating Capacity Resources.
- ♦ No Long Lead Time Generating Facilities secured a Queue Position to participate as a New Generating Capacity Resource.
- ♦ No de-list bids were rejected for reliability reasons.

ISO-NE asked the FERC to accept the FCA15 rates and results, effective June 26, 2021. Comments on this filing are due on or before April 12, 2021. Thus far, NESCOE and Public Citizen have filed doc-less interventions. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Essential Power Newington CIP IROL (Schedule 17) Cost Recovery Period Filing (ER21-1171)**

On February 18, 2021, Essential Power Newington, LLC ("EP Newington") requested FERC acceptance of a proposed rate schedule to allow EP Newington to begin the recovery period for certain Interconnection Reliability Operating Limits Critical Infrastructure Protection costs under Schedule 17 of the ISO-NE Tariff ("CIP-IROL Costs"). EP Newington stated that the rate schedule will provide interested parties notice of EP

[36] *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).

Newington's intent to recover CIP-IROL Costs for each affiliated facility designated as an IROL-Critical Facility, and an order accepting the rate schedule will provide an effective date after which associated costs incurred can be recovered following completion of the process contemplated by Schedule 17 and a subsequent section 205 filing identifying the specific costs to be recovered. A February 18, 2021 effective date was requested. Comments on this filing are due on or before March 11, 2021. Thus far, NESCOE has filed a doc-less intervention. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Bucksport CIP IROL (Schedule 17) Cost Recovery Period Filing (ER21-957)**

On January 27, 2021, Bucksport Generation LLC ("Bucksport") requested FERC acceptance of a proposed rate schedule to allow Bucksport to begin the recovery period for certain Interconnection Reliability Operating Limits Critical Infrastructure Protection costs under Schedule 17 of the ISO-NE Tariff ("CIP-IROL Costs"). Bucksport stated that the rate schedule will provide interested parties notice of Bucksport's intent to recover CIP-IROL Costs for each affiliated facility designated as an IROL-Critical Facility, and an order accepting the rate schedule will provide an effective date after which associated costs incurred can be recovered following completion of the process contemplated by Schedule 17 and a subsequent section 205 filing identifying the specific costs to be recovered. A March 29, 2021 effective date was requested. Comments on this filing were due on or before February 17, 2021; none were filed. NESCOE filed a doc-less intervention. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Stonepeak Kestrel CIP IROL (Schedule 17) Cost Recovery Period Filing (ER21-956)**

Also on January 27, 2021, Stonepeak Kestrel Energy Marketing LLC ("Stonepeak Kestrel") requested FERC acceptance of a proposed rate schedule to allow Stonepeak Kestrel to begin the recovery period for certain CIP-IROL Costs. Stonepeak Kestrel stated that the rate schedule will provide interested parties notice of Stonepeak Kestrel's intent to recover CIP-IROL Costs for each affiliated facility designated as an IROL-Critical Facility, and an order accepting the rate schedule will provide an effective date after which associated costs incurred can be recovered following completion of the process contemplated by Schedule 17 and a subsequent section 205 filing identifying the specific costs to be recovered. A March 29, 2021 effective date was requested. Comments on this filing were due on or before February 17, 2021; none were filed. NESCOE filed a doc-less intervention. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Dynegy CIP IROL (Schedule 17) Cost Recovery Period Filing (ER21-774)**

On February 26, 2021, the FERC accepted the rate schedule that Dynegy Marketing & Trade, LLC ("Dynegy") proposed to allow it to begin the recovery period for certain CIP-IROL Costs, effective March 1, 2021.[37] In accordance with the order, CIP-IROL Costs incurred from and after March 1, 2021 can be recovered following completion of the process contemplated by Schedule 17 and a subsequent section 205 filing identifying the specific costs to be recovered.[38] Unless the *Dynegy CIP IROL Cost Recovery Period 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).

- **Amended and Restated IRH Support and Use Agreements (ER21-712)**

On December 18, 2020, New England Hydro-Transmission Electric Company, Inc.; New England Hydro-Transmission Corporation; New England Electric Transmission Corporation; and Vermont Electric Transmission Company (collectively the "Asset Owners") and the IRH Management Committee ("IMC") on behalf of the renewing Interconnection Rights Holders ("IRH") submitted for approval an Offer of Settlement that amends

[37] *Dynegy Marketing & Trade, LLC*, 174 FERC ¶ 61,155 (Feb. 26, 2021) ("*Dynegy CIP IROL Cost Recovery Period Order*").

[38] *Id.* at P 8.

and restates four Support Agreements and an Agreement with Respect to Use of Québec Interconnection ("Use Agreement")[39] to provide for ongoing financial support of, and related rights and obligations with respect to, the United States portion of the 2,000 MW high-voltage, direct current ("HVDC") transmission facilities interconnecting New England and Québec. The initial term of the existing Support Agreements was scheduled to end on October 31, 2020, and the Use Agreement by its own terms will remain in effect though the term of the last Support Agreement to expire. The filing extends the term of those Support Agreements (and thereby the Use Agreement) another 20 years, until October 31, 2040. A January 1, 2021 effective date was requested. Comments on this filing were due on or before January 8, 2021; none were filed. Avangrid, ENE, NESCOE, and Eversource (out-of-time) filed doc-less interventions. This matter is pending before the FERC. If you have any questions concerning these matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

As previously reported, the FERC issued four orders in this proceeding in July 2020 (three on July 17 (together, the "*July 17 Orders*"); one on July 28, 2020). Each of the orders addressed in part or in whole the Cost-of-Service Agreement ("COS Agreement")[40] among Constellation Mystic Power ("Mystic"), Exelon Generation Company ("ExGen") and ISO-NE, which is to provide compensation for the continued operation of the Mystic 8 & 9 units from June 1, 2022 through May 31, 2024. As noted in Section XV below, each of the *July 17 Orders*[41] (and the earlier, underlying orders) have been appealed to the DC Circuit. Two aspects of this proceeding remain pending before the FERC:

ROE Paper Hearings (-000). The *Dec 2018 Order* established a paper hearing to determine the just and reasonable ROE to be used in setting charges under Mystic's COS Agreement. On April 19, 2019, Mystic, Connecticut Parties, ENECOS, MA AG, and FERC Trial Staff filed initial briefs. On July 18, 2019, Constellation Mystic Power, CT Parties, ENECOS, MA AG, National Grid, FERC Trial Staff filed reply briefs. In a July 28, 2020 order,[42] the FERC reopened the record to allow parties an opportunity to present written evidence applying the FERC's *Opinion 569-A* ROE methodology to the facts of this proceeding. CT Parties, EMCOS, MA AG, and FERC Trial Staff filed their initial "Opinion 569-A" briefs on September 28, 2020. Responses to those initial briefs were due October 28, 2020 and were filed by Mystic, CT Parties, ENECOS, and FERC Trial Staff. The ROE issue is now pending before the Commission.

[39] The Support Agreements are separate contracts between the IRH and each of the Asset Owners under which the IRH agree to financially support the elements of the Phase I/II HVDC-TF owned by each Asset Owner in exchange for rights to use the transmission capacity of the Phase I/II HVDC-TF to transmit power to and from the HQ system ("Use Rights"). The Use Agreement is a contract among the IRH that provides the rules for the exercise of the Use Rights, for making the Use Rights available to others, and for the collective management of those individual contractual rights through the IRH Management Committee.

[40] The COS Agreement, submitted on May 16, 2018, is between Mystic, Exelon Generation Company, LLC ("ExGen") and ISO-NE. The COS Agreement is to provide cost-of-service compensation to Mystic for continued operation of Mystic 8 & 9, which ISO-NE has requested be retained to ensure fuel security for the New England region, for the period of June 1, 2022 to May 31, 2024. The COS Agreement provides for recovery of Mystic's fixed and variable costs of operating Mystic 8 & 9 over the 2-year term of the Agreement, which is based on the pro forma cost-of-service agreement contained in Appendix I to Market Rule 1, modified and updated to address Mystic's unique circumstances, including the value placed on continued sourcing of fuel from the Distrigas liquefied natural gas ("LNG") facility, and on the continued provision of surplus LNG from Distrigas to third parties.

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

[42] *Constellation Mystic Power, LLC*, 172 FERC ¶ 61,093 (July 28, 2020), *order addressing arguments on reh'g*, 173 FERC ¶ 61,261 (Dec. 21, 2020).

Sep 2020 Compliance Filing (-007). On September 15, 2020, Mystic filed a revised COS Agreement in response to the requirements of the *July 17 Compliance Order*. Also included were typographical edits proposed by NESCOE in its protest of the First Compliance Filing. Mystic also filed revisions to the Fuel Security Agreement ("FSA") for informational purposes because some of the compliance directives required changes to the FSA. Comments on the Sep 2020 Compliance Filing were due on or before October 6, 2020. CT Parties and ENECOS protested the compliance filing. On October 21, 2021, Mystic answered the CT Parties' and ENECOS' protests. The compliance filing remains pending before the FERC.

Feb 2021 Compliance Filing (-008). On February 25, 2021, Mystic filed a revised COS Agreement in a third compliance filing, this time in response to the requirements of the FERC's *Dec 21, 2020 Third Compliance Order*.[43] The Feb 2021 Compliance Filing proposes changes to section 2.4 of the COS Agreement to align that section with the FERC's direction that the Agreement's clawback mechanism apply to costs "that are incurred" rather than those that "that were expensed." Comments on the third compliance filing are due on or before March 18, 2021.

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).

- **MPD OATT 2019 Annual Informational Filing Settlement Agreement (ER15-1429-014)**

On December 28, 2020, Versant Power submitted an uncontested Joint Offer of Settlement between itself, MPUC, MOPA, and the MCG to resolve certain issues raised by the MPUC and the MCG with regards to Versant Power's annual charges update under the Open Access Transmission Tariff for Maine Public District ("MPD OATT"), as filed in Docket No. ER15-1429-000 on May 1, 2019, and revised on May 16, 2019 (together, the "2019 Annual Update").[44] Initial comments and reply comments were due January 18 and 27, 2021, respectively; 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).

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

- **Elimination of Price Lock and Zero-Price Offer Rule for New Entrants Starting in FCA16 (ER21-1010)**

In response to the requirements of the *December 2 Order*,[45] ISO-NE submitted on February 1, 2021, Tariff revisions eliminating the price lock and associated zero-price offer rule for new entrants starting in FCA16. The ISO-NE's proposed compliance changes were supported by the Participants Committee at its February 4 meeting (Consent Agenda Item No. 4). Comments on ISO-NE's filing were due on or before February 22, 2021. Comments supporting the Tariff revisions were filed by NEPOOL (February 9) and NEPGA (February 23). No adverse comments were filed. Doc-less interventions were filed by BSW ProjectCo, Calpine, Eversource, National Grid, NESCOE, and NRG. This matter is pending before the FERC.

As described in previous Reports, the FERC, in response to a February 2, 2018 remand by the United States Court of Appeals for the District of Columbia Circuit ("DC Circuit"),[46] found preliminarily that ISO-NE's new entrant

[43] *Constellation Mystic Power, LLC*, 173 FERC ¶ 61,261 (2020) ("*Dec 21, 2020 Third Compliance Order*")

[44] As previously reported, MCG moved to strike the true-up to actuals portion of the 2019 Annual Update to the extent that the true-up proposed a change in the formula rate from a direct assignment of Maine Public District ("MPD") post-retirement benefits other than pensions ("PBOPs") to an allocation of company-wide PBOPs (which MCG argued would be a retroactive change to the formula rate, otherwise required to effect only prospectively).

[45] *ISO New England Inc.*, 173 FERC ¶ 61,198 (Dec. 2, 2020) ("*December 2 Order*") (finding the price-lock mechanism and zero-price offer rule ("New Entrant Rules") no longer just and reasonable and directing ISO-NE to remove the New Entrant Rules from the Tariff).

[46] *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) after finding 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).

rules may be unjust and unreasonable.[47] The FERC established paper hearing procedures, which included one round of briefs and reply briefs submitted in the late summer and early fall of 2020.[48] The *December 2 Order* found the New Entrant Rules no longer just and reasonable and directed ISO-NE to remove them from the Tariff.[49]

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).

- **EER Exemption from PFP Settlement (ER21-943)**

On January 26, 2021, ISO-NE filed revisions to the Tariff (including related revisions to the FAP) to exclude energy efficiency resources ("EERs") from Pay-for-Performance ("PFP") obligations and settlement in all hours. EER capacity base payments are unaffected. The EER Exemption was considered, but not supported, by the Participants Committee at its October 2, 2020 meeting. The related FAP revisions were considered but were supported by the Participants Committee at the same meeting. An April 1, 2021 effective date was requested.[50] Comments on this filing were due on or before February 16, 2021. Comments supporting the revisions were filed by: NEPOOL; the ISO-NE Internal Market Monitor ("IMM"); LS Power Development, Helix Maine Wind Development, Ocean State Power, and Wallingford Energy (collectively, the "LS Power companies"); and NEPGA. AEE filed comments protesting the revisions, which ISO answered on March 3, 2021. Doc-less interventions were filed by Calpine, Dominion; Eversource, MA AG, National Grid, NESCOE, NRG, and Vistra. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

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

On December 31, 2020, ISO-NE filed changes to update the Cost of New Entry ("CONE"), Net CONE, and Payment Performance Rate ("PPR") values beginning with FCA16. The values in this filing are the same CONE, Net CONE and PPR values that the NPC approved at its December 5 meeting as part of a broader FCM updates package; however, this filing did not include the updated Offer Review Trigger Prices ("ORTPs"), which were part of the broader package, and on which NEPOOL and ISO-NE will propose alternative values in a jump ball filing to be submitted later this month. ISO-NE explained in its filing that, if the schedule for FCA16 is to be maintained, the updated CONE, Net CONE and PPR values need to be acted on by the FERC and become effective by early March, 2010 (a March 2, 2021 effective date was requested). ISO-NE stated that the revised ORTPs and related Tariff changes, however, do not need to be effective until slightly later in the FCA16 qualification process (thereby permitting a slightly later submission of, and FERC action on, the various ORTPs and related Tariff changes). Because NEPOOL did not vote on the CONE, Net CONE and PPR values separately, but rather as part of a broader package with the alternative ORTP provisions, NEPOOL did not join this ISO-NE filing but will provide comments in response to the filing explaining the December 5 NEPOOL vote on the package of proposed FCM parameters.

Comments on this ISO-NE filing were due on or before January 21, 2021. Comments were filed by NEPOOL, MMWEC, NESCOE, and CT Agencies. Protests were filed by CPV Towantic, Dominion, FirstLight, NEPGA, and NEI. Doc-less interventions were filed by Avangrid, Brookfield, BSW Project Co, Calpine, Cogentrix, Dominion,

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

48 Initial briefs, due Aug. 24, 2020, 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 Sept. 23, 2020 and were filed by 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 were permitted. No additional answers or briefs were permitted.

49 *December 2 Order* at PP 1, 77.

50 ISO-NE requested in the alternative, that the revisions be accepted effective with FCA16 (June 1, 2025) should the FERC not grant an April 1, 2021 effective date.

Eversource, CT AG, CT OCC, CT DEEP, CT PURA, LS Power, MA AG, National Grid (out-of-time), NESCOE, NHEC, NRG, Vistra, EPSA, and MA DPU (out-of-time). On February 12, ISO-NE answered the protests filed. On February 16 and 17, answers to ISO-NE's February 12 answer were filed by EPSA, NEPGA and CPV Towantic.

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

If you have any questions concerning this proceeding, please contact Dave Doot (dtdoot@daypitney.com; 860-275-0102), Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **New DDBT Methodology (ER21-782)**

On March 1, the FERC accepted proposed Tariff revisions to implement a new methodology for calculating the FCM Dynamic De-List Bid Threshold ("DDBT").[51] As previously reported, the new DDBT Methodology will replace the current triennial update methodology with an annual one, with the DDBT to be calculated annually for each FCA, using a new Tariff-based DDBT calculation methodology. That methodology, referred to as the "recalibration method," updates the DDBT value for each auction based on the most recently available supply conditions, as evidenced in the last FCA, and the most up-to-date projected demand conditions, using the estimated system-wide demand curve for the next FCA. The new DDBT methodology filed was the compromise DDBT proposal overwhelmingly approved by the Participants Committee in November, rather than the one that had been offered by ISO-NE. The new DDBT methodology was accepted effective as of March 2, 2021, as requested. Unless the *New DDBT Methodology Order* is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **EER FCM Qualification Modifications (ER21-640)**

On February 11, 2021, the FERC accepted the EER FCM Qualification Modifications, effective as of February 12, 2021, as requested.[52] As previously reported, the "EER FCM Qualification Modifications" implement changes to the Market Rules (i) to produce Qualified Capacity values that better reflect performance capabilities of EERs; (ii) to modify the rules that determine the quantity of Capacity Supply Obligation ("CSO") that a resource of any type may acquire in monthly reconfiguration auctions or CSO Bilateral transactions to increase trading opportunities; and (iii) to reflect a number of conforming and clean-up changes. Unless the February 11 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).

[51] *ISO New England Inc. and New England Power Pool Participants Comm.*, 174 FERC ¶ 61,162 (Mar. 1, 2021) ("*New DDBT Methodology Order*").

[52] *ISO New England Inc. and New England Power Pool Participants Comm.*, Docket No. ER21-640-000 (Feb. 11, 2021) (unpublished letter order).

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

As previously reported, the FERC conditionally accepted both the November 22, 2019[53] and February 10, 2020[54] *Order 841*[55] compliance filings, each subject to additional compliance filing(s). On December 7, 2020, ISO-NE and NEPOOL filed, in one comprehensive filing, revisions to Market Rule 1 in response to the requirements of the *Order 841 Compliance Filing II Order*.[56] Those revisions were accepted on February 10, 2021.[57] The revisions accepted became effective on March 1, 2021, with the exception of the revisions specific to the Day-Ahead Energy Market, which will become effective on January 1, 2026. Unless the February 10 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).

- **CASPR (ER18-619)**

On February 18, 2021, the FERC issued an order rejecting,[58] as procedurally barred, the Sierra Club/NRDC/CLF request for rehearing of the November 19 *CASPR Allegheny Order*.[59] The FERC had earlier issued a notice[60] that the Sierra Club/NRDC/CLF request for rehearing of the November 19 *CASPR Allegheny Order* was denied by operation of law and would be addressed in a future order. This matter is on appeal before the DC Circuit (*see* Section XV below, Case No. 20-1333). 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).

IV. OATT Amendments / TOAs / Coordination Agreements

- ***Order 676-I* Compliance Filing (ER21-946)**

On January 26, 2021, ISO-NE and NEPOOL, in response to *Order 676-I*, jointly filed changes to incorporate by reference in Schedule 24 of the OATT the latest version (Version 003.2) of certain Standards for Business Practices and Communication Protocols for Public Utilities adopted by the Wholesale Electric Quadrant ("WEQ") of the North American Energy Standards Board ("NAESB"). The Participants Committee unanimously supported the *Order 676-I* revisions at its May 7, 2020 meeting. Comments on this filing were due on or before February 16, 2021; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

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

55 *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*").

56 The compliance filing included revisions addressing (i) the application of transmission charges; (ii); ISO-NE Market participation (ensuring the Tariff cannot be read to create a barrier to entry); and (iii) how state of charge and duration characteristics will be accounted for in the Day-Ahead Energy Market.

57 *ISO New England Inc. and New England Power Pool Participants Comm.*, Docket No. ER19-470-005 (Feb. 10, 2021) (unpublished letter order).

58 *ISO New England Inc.*, 174 FERC ¶ 61,120 (Feb. 18, 2021) ("*Order Rejecting Rehearing of CASPR Allegheny Order*")(Rehearing does not lie where the FERC did not change the outcome of the order appealed from).

59 *ISO New England Inc.*, 173 FERC ¶ 61,161 (Nov. 19, 2020) ("*CASPR Allegheny Order*").

60 *ISO New England Inc.*, 174 FERC ¶ 62,041 (Jan. 21, 2021).

V. Financial Assurance/Billing Policy Amendments

- **FAP Info Disclosure/KYC Requirements (ER21-816)**

On March 3, 2021, the FERC accepted the revisions to the FAP, jointly filed by ISO-NE and NEPOOL on January 6, 2021 (as amended on February 23, 2021[61]).[62] As previously reported, the revisions (i) update FAP information disclosure requirements; (ii) update risk management disclosure requirements; and (iii) add a provision regarding prior uncured payment defaults and entry into the New England Markets (collectively, the "FAP Info Disclosure/KYC Requirements"). The revisions were accepted as of March 9, 2021, as requested. Unless the March 3 order is challenged this proceeding will be concluded. ***Please note***: each Market Participant will have to submit, on or before April 30, 2021, the form of Information Disclosure approved in this proceeding (even if the former version was already submitted in 2021). 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 NEP-Vitol Phase I/II HVDC-TF Service Agreement (ER21-1180)**

On February 19, 2021, New England Power Company ("NEP") submitted a new Phase I/II HVDC-TF Service Agreement between NEP and Vitol Inc. ("Vitol"). The Service Agreement, based on the *pro forma* Phase I/II HVDC-TF Service Agreement set forth in Schedule 20A-Common Attachment A, provides for firm point-to-point transmission service over the Phase I/II HVDC transmission facilities ("Phase I/II HVDC-TF") for the November 1, 2020 to November 1, 2025 period. The Agreement was filed separately because it contains potentially non-conforming terms that provide Vitol a right to terminate the Agreement if it finds unacceptable the terms and conditions of the Amended and Restated IRH Support and Use Agreements pending in ER21-712 (*see* Section II above). NEP requested a November 1, 2020 effective date for Agreement. Comments on this filing are due on or before March 12, 2021. Thus far, Vitol has submitted a doc-less intervention. If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Schedule 20A-VP: Versant Power-Vitol Phase I/II HVDC-TF Service Agreement (ER21-827)**

On January 7, 2021, Versant Power submitted a non-conforming Phase I/II HVDC-TF Service Agreement between itself and Vitol Inc. ("Vitol") for firm service under Schedule 20A-VP. Versant Power requested a November 1, 2020 effective date for the Agreement. Comments on this filing were due on or before January 28, 2021; none were filed. Vitol filed a doc-less intervention. This matter is pending before the FERC. If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

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

[61] The "Feb 23 Amendment" re-formatted the footnote text so that the text will be visible in the FERC's eTariff system. No changes to the text were made.

[62] *ISO New England Inc. and the New England Power Pool Participants Comm.*, Docket Nos. ER21-816-000 and -001 (Mar. 3, 2021) (unpublished letter order).

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,*[63] and certified by Settlement Judge Dring[64] to the Commission,[65] 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).

- **Schedule 21-GMP Annual True Up Calculation Forecast Info Report (ER12-2304)**

On January 15, 2021, pursuant to Section 4 of Schedule 21-GMP, Green Mountain Power ("GMP") supplemented its annual informational filing containing the forecast of its costs for the January 1, 2021 through December 31, 2021 time period. The supplement does not change the 2021 forecasted rates previously filed, but does contain a material accounting change to adjust the 2021 charges billed under the Formula Rate in connection with the sale of its share of the Highgate facility. GMP also disclosed that it is not using historical ADIT for this forecast. The FERC will not notice this filing for public comment, and absent further activity, no further FERC action is expected. If there are questions on this matter, 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).

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[63] *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.

[64] 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.

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

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

The TOs' November 2, 2015 refund report documenting resettlements of regional transmission charges by ISO-NE in compliance with *Opinions No. 531-A*[66] *and 531-B*[67] also remains pending. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

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

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

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

- **Capital Projects Report - 2020 Q4 (ER21-1109)**

On February 11, 2021, ISO-NE filed its Capital Projects Report and Unamortized Cost Schedule covering the fourth quarter ("Q4") of calendar year 2020 (the "Report"). ISO-NE is required to file the Report under section 205 of the FPA pursuant to Section IV.B.6.2 of the Tariff. Report highlights include the following new projects: (i) nGEM software development part II ($4.79 million); (ii) Integrated Market Simulator Phase 1 ($1.6 million); (iii) FCM Qualification Enhancements ($1.2 million); (iv) CIP Electronic Security Perimeter Redesign ($1.1 million); (v) Sub-accounts for FTR Market ($0.98 million); (vi) Enterprise Phone System Upgrade ($701,300); (vii) Wireless Infrastructure Upgrade ($548,900); (viii) Time Entry System Upgrade ($398,200); (ix) Ownership Transfer & External Registration ($382,700); (x) PI Historian for Short-term PMU Data Repository ($368,800); (xi) Annual Maintenance Schedule Automation ($315,800); and (xii) FERC Form 1, 3-Q and 714 Project ($162,400). There were no significant changes for Chartered Projects in 2020 Q4. Comments on this filing are due on or before March 4, 2021. NEPOOL filed comments on February 17 supporting the Q4 Report. 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 Q4 2020 (ER19-1951)**

On February 16, 2021, ISO-NE filed, as required,[68] public and confidential[69] versions of its Interconnection Study Metrics Processing Time Exceedance Report (the "Exceedance Report") for the Fourth Quarter of 2020 ("2020 Q4"). ISO-NE reported that five of the six 2020 Q4 ***Interconnection Feasibility Study ("IFS") reports*** delivered to Interconnection Customers were delivered later than the best efforts completion timeline.[70] In addition, three IFS Reports that are not yet completed have exceeded the 90-day completion expectation. The average mean time from ISO-NE's receipt of the executed IFS Agreement to delivery of the completed IFS report to the Interconnection Customer was 178.5 days (down from 251 in 2020 Q3). All three ***System Impact Study ("SIS") reports*** delivered to Interconnection Customers were 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 580 days (up from 458 in 2020 Q3). There were no

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

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

[68] 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.

[69] 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.

[70] 90 days from the Interconnection Customer's execution of the study agreement.

Interconnection Requests with projects in the Interconnection Facilities Study phase of the interconnection process. Section 4 of the Report identified steps ISO-NE has identified to remedy issues and prevent future delays, including mitigating the impact of backlogs and initiating clustering, moving to earlier in the process certain Interconnection Customer data reviews, and enhanced information sharing and coordination efforts with Interconnecting TOs. This report was not noticed for public comment.

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

On January 29, 2021, ISO-NE filed, as required under Section 4.1(j)(iii) of the OATT, its annual informational filing of projects on the Regional System Plan ("RSP") project list that had a year of need three years or less from the completion of the Needs Assessment. The list of prior year designations is maintained on the ISO-NE website at https://www.iso-ne.com/static-assets/documents/2021/01/2020-prior-year-projects-section-4-j-iii-final.pdf. This filing will not be noticed for public comment by the FERC.

- **IMM Quarterly Markets Reports – Fall 2020 (ZZ21-4)**

On February 5, 2021, the IMM filed with the FERC its Fall 2020 report of "market data regularly collected by [the IMM] in the course of carrying out its functions under … Appendix A and analysis of such market data," as required pursuant to Section 12.2.2 of Appendix A to Market Rule 1. These filings are not noticed for public comment by the FERC. The Fall 2020 Report will be discussed with the Markets Committee at its March 9-10, 2021 meeting.

IX. Membership Filings

- **March 2021 Membership Filing (ER21-1228)**

On February 26, 2021, NEPOOL requested that the FERC accept: (i) the membership of Trafigura Trading LLC (Supplier Sector); (ii) the termination of Axon Energy (Supplier Sector) and Springfield Power [Related Person to Stored Solar J&WE, LLC (AR Sector)]; and (iii) to reflect Titan Gas LLC's d/b/a as CleanSky Energy. Comments on this filing are due on or before February 19, 2021.

- **February 2021 Membership Filing (ER21-1008)**

On January 29, 2021, NEPOOL requested that the FERC accept: (i) the memberships of the following: Axpo U.S. LLC (Supplier Sector); Catalyst Power & Gas, LLC (Supplier Sector); Palm Energy LLC (Provisional Member); Madison ESS, LLC [Related Person to Madison BTM and New England Battery Storage (Generation Group Seat)]; Rumford ESS, LLC [Related Person to Madison BTM and New England Battery Storage (Generation Group Seat)]; Vineyard Reliability LLC (Generation Group Seat); West Medway II, LLC [Related Person to Exelon Generation Company and Constellation NewEnergy, Inc. (Supplier Sector)]; and Dick Brooks (End User Sector, Governance Only Member); (ii) the termination of the Participant status of: Energy Federation Inc. ("EFI") (AR Sector, LR Sub-Sector, Small LR Group Seat); Great American Power, LLC (Supplier Sector); Oasis Power, LLC d/b/a Oasis Energy [Related Person to Spark Energy et al., (Supplier Sector)]; Praxair, Inc. (End User Sector); Rubicon NYP Corp. (Supplier Sector); and Verde Group, LLC (Provisional Member); and (iii) the Name change of Utility Services of Vermont (f/k/a Utility Services, Inc.). Comments on this filing were due on or before February 22, 2021; none were filed. This matter is pending before the FERC.

- **January 2021 Membership Filing (ER21-761)**

On February 25, 2021, the FERC accepted: (i) the memberships of the following Supplier Sector Participants: Cassadaga Wind LLC; Centrica Business Solutions Optimize, LLC; Pilot Power Group, LLC; and SmartestEnergy US LLC; and (ii) the termination of the Participant status of Wheelabrator Bridgeport, LP.[71] Unless the February 25 order is challenged, this proceeding will be concluded.

[71] *New England Power Pool Participants Comm.*, Docket No. ER21-761 (Feb. 25, 2021) (unpublished letter order).

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

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

- **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,[72] 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[73] 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.

- **NERC Annual Report on FFT & Compliance Exception Programs (RC11-6-011)**

On February 19, 2021, the FERC accepted NERC's annual report on Find, Fix, and Track ("FFT") and Compliance Exception programs.[74] As previously reported, the annual FFT report was submitted in accordance with prior FERC Orders.[75] In the 2020 report, NERC stated that the ERO Enterprise appropriately handles noncompliance posing a minimal or moderate risk through these programs and that the results of the annual report show consistent improvement in program implementation. The report also demonstrates, NERC suggests, significant alignment across the ERO Enterprise, particularly in the processing and understanding of the risk associated with individual noncompliance. Unless the February 19 order is challenged, this proceeding will be concluded.

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[72] 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").

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

[74] *N. Am. Elec. Rel. Corp.*, Docket No. RC11-6-011 (Feb. 19, 2021) (unpublished letter order).

[75] *See N. Am. Elec. Rel. Corp.*, 138 FERC 61,193 (2012) ("March 2012 Order"); *N. Am. Elec. Rel. Corp.,* 143 FERC 61,253 (2013) ("June 2013 Order"); *N. Am. Elec. Rel. Corp.,* 148 FERC 61,214 (2014) ("September 2014 Order"); and *N. Am. Elec. Rel. Corp.*, Docket No. RC11-6-004 (Nov. 13, 2015) (unpublished letter order) ("November 2015 Order").

- **Revised Reliability Standard: FAC-008-5 (RD21-4)**

On February 19, 2021, NERC filed for approval proposed changes to Reliability Standard FAC-008-5 (Facility Ratings). FAC-008-5 reflects the retirement of Requirement R7, recommended as part of NERC's Standards Efficiency Review because of its redundancy with requirements in other Reliability Standards. NERC asked that FAC-008-5 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 FAC-008-5 are due on or before March 22, 2021.

- **Revised Reliability Standards: CIP-013-2, CIP-005-7, CIP-010-4 (RD21-2)**

On December 14, 2020, NERC filed for approval proposed changes to Reliability Standards CIP-013-2, CIP-005-7, and CIP-010-4 (the "Supply Chain Standards"). The Supply Chain Standards address supply chain cybersecurity risk management, broadening requirements to include Electronic Access Control or Monitoring Systems ("EACMS") and Physical Access Control Systems ("PACS") as applicable systems. NERC asked that the Supply Chain Standards become effective (and the currently effective versions be retired) on the first day of the first calendar quarter that is 18 months following FERC approval. Comments on the Supply Chain Standards were due on or before January 28, 2021; none were filed. This matter is pending before the FERC.

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

As previously reported, NERC is required to file on an informational basis quarterly status updates regarding the development of new or modified Reliability Standards pertaining to virtualization and cloud computing services (resulting from Projects 2016-02 (Modifications to CIP Standards) and 2019-02 (BES Cyber System Information Access Management)). NERC filed its fourth informational filing on December 15, 2020, reporting no change in schedule for either project from that reported in its supplemental November 2020 filing -- filing of proposed Reliability Standards in December 2021 for both Projects (2019-02 and 2016-02).

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

On February 5, 2021, NERC withdrew its proposed 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, "in light of recent cybersecurity events and the evolving threat landscape, … additional caution is warranted regarding any criteria that may permit more entities to categorize Bulk Electric System ("BES") Cyber Systems as low impact, such as the revisions proposed in CIP-002-6, and recommends further study." Accordingly, reporting on this proceeding is now concluded.

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

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

Comments were filed by NERC, the ISO/RTO Council ("IRC"), APPA/LPPC, Canadian Electricity Assoc. ("CEA"), Cogentrix, EEI/EPSA, Forescout Technologies, MISO TOs, NJ BPU, NRECA, Reliable Energy Analytics, Southwestern Power Administration, SEIA, Siemen's Energy, Southern Companies, TAPS, U.S. Bureau of Reclamation, U.S Corp of Army Engineers, Western Area Power Administration ("WAPA"), Wolverine Power Supply Cooperative, XTec, and J. Applebaum, J. Christopher/T. Conway, and 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.[76] On March 25, 2020, Joint Associations[77] requested an extension of time to submit comments and reply comments. On April 2, the FERC granted Joint Associations' request and extended the deadline for initial comments on the NOI to July 1, 2020; the deadline for reply comments, July 31, 2020. Comments were filed by NERC, the IRC, Accenture, Amazon Web Services ("Amazon"), Bonneville, the Bureau of Reclamation, Barry Jones, Georgia System Operations, GridBright, Idaho Power, Microsoft, MISO, MISO Transmission Owners, Siemens Energy Management, Tri-State Generation and Transmission Association, VMware, Inc., AEE, American Association for Laboratory Accreditation ("A2LA"), APPA, Canadian Electricity Assoc., EEI, NRECA, and Waterfall Security Solutions. Reply comments were due on or before July 31, 2020, and were filed by AEE, Amazon and Microsoft.

In part in response the comments filed, the FERC, in a December 17, 2020 order,[78] directed NERC to begin a formal process to assess, and to make an informational filing in a little over one year (January 1, 2022) that addresses, the feasibility of voluntarily conducting BES operations in the cloud in a secure manner, as well as the status and schedule for any plans to modify the standards.

- ***Order 873*** **- Retirement of Reliability Standard Requirements (Standards Efficiency Review) (RM19-17; RM19-16)**

On September 17, 2020, the FERC approved the retirement of the 18 Reliability Standard requirements through the retirement of four Reliability Standards and the modification of five Reliability Standards,[79] 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."[80] 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.[81]

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*[82] (the "MOD A Reliability Standards"). The FERC intends

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

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

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

[79] *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).

[80] *Order 873* at P 2.

[81] *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.

[82] *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

to coordinate the effective dates for the retirement of the MOD A Reliability Standards with successor North American Energy Standards Board ("NAESB") business practice standards (v. 003.3) that include Modeling business practices pending in the *NAESB WEQ v. 003.3 Standards NOPR* (*see* Section XII below).[83]

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

NERC's October 14, 2020 petition for FERC approval of its amended and restated Bylaws remains pending. As previously reported, NERC stated that the amendments (i) address governance matters relating to the composition of NERC's membership Sectors, certain rules relating to the Member Representatives Committee, as well as the qualification of independent trustees for the Board; (ii) update certain provisions to conform with applicable state law; and (iii) improve internal consistency and introduce ministerial changes within the Bylaws with respect to capitalizing defined terms consistently and removing inoperative provisions. Comments, if any, on the Amended and Restated Bylaws were due on or before November 4, 2020; none were filed. This matter remains pending before the FERC.

XI. Misc. - of Regional Interest

- **203 Application: Exelon Generation (EC21-57)**

On February 25, 2021, Exelon Generation Company, LLC ("ExGen"), on behalf of its public utility subsidiaries, requested authorization for a "spin" transaction in which, after completion of an internal reorganization, the ownership of Applicants' intermediate holding company owner, HoldCo, will be distributed to the shareholders of Applicants' current ultimate upstream owner, Exelon Corporation (the "Transaction"). Following the Transaction, Exelon Corporation and its remaining subsidiaries will retain no interest in or affiliation with ExGen or the ExGen Utility Subsidiaries; Exelon Corporation and HoldCo will be separate publicly-traded companies. Comments on this filing are due on or before March 18, 2021. Thus far, doc-less interventions have been filed by PJM, PJM IMM and Public Citizen. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **SGIA Cancellation: CL&P/Covanta Wallingford (ER21-867)**

On January 11, 2021, CL&P filed a notice of cancellation of the Small Generator Interconnection Agreement ("SGIA") between itself and Covanta Projects of Wallingford, L.P. ("Covanta Wallingford") (designated as service agreement IA-NU-16 and accepted in Docket No. ER10-1654), reflecting the request of Covanta Wallingford, whose Non-Price Retirement request notice was accepted by ISO-NE on December 17, 2014. A January 11, 2021 effective date for the notice of cancellation was requested. Comments on this filing were due on or before February 1; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **LGIA Cancellation: Mt. Tom (ER21-845)**

On January 7, 2021, ISO-NE and Eversource filed a notice of cancellation of the Large Generator Interconnection Agreement ("LGIA") governing the interconnection of Mt. Tom Station. On June 1, 2018, Engie Energy Marketing NA, Inc. formally retired the Mt. Tom Station from the New England Markets. Decommissioning work on the facility began in 2018 and was substantially completed as of February 2020. The interconnection rights for Mt. Tom Station terminated upon the date of its retirement. This filing is to terminate the Original Service Agreement. A March 8, 2021 effective date was requested. Comments on this filing were due on or before January 28; 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).

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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.

[83] *Standards for Bus. Practices and Communication Protocols for Pub. Utils.*, 85 Fed. Reg. 55201 (Sep. 4, 2020).

- **LGIA: NSTAR / MMWEC (Stony Brook) (ER21-777)**

On February 26, 2021, the FERC accepted an LGIA between NSTAR and MMWEC for the continued interconnection of MMWEC'S Stony Brook Generating Station located in Ludlow, Massachusetts to NSTAR's transmission system.[84] As previously reported, the LGIA replaces the original 1992 Stony Brook interconnection agreement which, as previously reported, had been extended three times[85] and expired on December 31, 2020. Since the LGIA covers an existing, interconnected facility, and does not set forth any terms or conditions that would otherwise modify the interconnection services provided under the original IA, NSTAR states that a new three-party interconnection agreement (that would include ISO-NE) was not required. The LGIA was accepted effective as of December 31, 2020, as requested. Unless the February 26 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).

- **LGIA: CMP / ReEnergy Stratton (ER21-769)**

On February 19, 2021, the FERC accepted an LGIA that renews and replaces the terms of an original interconnection agreement entered into between CMP and ReEnergy Stratton's predecessor in interest (Stratton Energy Associates).[86] The LGIA was accepted effective as of December 21, 2020, as requested. Unless the February 19 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).

- **Interim Distribution Wheeling Agreement: Unitil / Briar Hydro (ER21-759)**

On February 22, 2021, the FERC accepted an Interim Distribution Wheeling Service Agreement between Unitil Energy Systems ("UES") and Briar Hydro Associates ("Briar").[87] The Agreement provides for Briar's ongoing receipt of distribution wheeling services for the Penacook Lower Falls Resource[88] (pending UES' filing of a distribution wheeling rate in early 2021). Briar intends to sell the output of the facility into the New England Market. The Agreement was accepted effective as of December 28, 2020, as requested. Unless the February 22 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement Cancellation: NSTAR / SEMASS (ER21-676)**

On February 11, 2021, the FERC accepted, effective December 21, 2020, a notice of cancellation of a Design and Engineering Agreement ("D&E Agreement") between NSTAR and SEMASS Partnership ("SEMASS").[89] As previously reported, the D&E Agreement set forth the terms and conditions under which NSTAR undertook preliminary engineering, design and construction activities on its interconnection facilities to accommodate SEMASS's planned construction activity at its switchyards within its generation station. The D&E Agreement terminated by its terms on July 1, 2020 and all billing reconciliations under the D&E Agreement since completed. The notice of cancellation was accepted effective as of December 17, 2020, as requested. Unless the February 11 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).

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[84] *NSTAR Elec. Co.*, Docket No. ER21-777 (Feb 26, 2021) (unpublished letter order).

[85] *See NSTAR Elec. Co.*, Docket No. ER19-2303 (Feb. 22, 2019) (unpublished letter order) (1st extension); *NSTAR Elec. Co.*, Docket No. ER19-2303 (Aug. 22, 2019) (unpublished letter order) (2nd extension); *NSTAR Electric Co.,* Docket No. ER19-2897 (Nov. 5, 2019) (unpublished letter order) (3rd extension).

[86] *Central Maine Power Co.*, Docket No. ER21-769 (Feb. 19, 2021) (unpublished letter order).

[87] *Unitil Energy Systems, Inc.*, Docket No. ER21-759 (Feb. 22, 2021) (unpublished letter order).

[88] The Penacook Lower Falls Resource is a 4.5 MW hydro unit located in Boscawen, New Hampshire on the southern bank of the Contoocook River.

[89] *NSTAR Electric Co.*, Docket No. ER21-676 (Feb. 11, 2021) (unpublished letter order).

- **SGIA: CL&P / ECRRA (ER21-651)**

On February 19, 2020, the FERC accepted a SGIA between CL&P and Eastern Connecticut Resource Recovery Authority ("ECRRA") that allows for the continued interconnection of ECRRA's refuse-to-energy municipal solid waste facility.[90] As previously reported, ECCRA, through Wheelabrator North Andover, intends to sell the output of the facility into the New England Market. The SGIA was accepted effective as of December 15, 2020, as requested. Unless the February 19 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).

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

In accordance with *Order 864*[91] and *Order 864-A,*[92] and extensions of time granted, New England's public utilities with transmission have submitted their *Order 864* compliance filings, with the specific dockets and filing dates identified in the following table (all remain pending):

Date Filed	Docket	Transmission Provider	Date Accepted
Feb 16, 2021	ER21-1154	Fitchburg Gas & Electric ("FG&E")	pending
Oct 30, 2020	ER21-311	Green Mountain Power	pending
Aug 5, 2020	ER20-2614	New England Power Support Agreement	pending
Aug 5, 2020	ER20-2610	CL&P	pending
Aug 5, 2020	ER20-2609	NSTAR	pending
Aug 5, 2020	ER20-2608	PSNH	pending
Aug 4, 2020	ER20-2607	NEP – Seabrook Transmission Support Agreement	pending
Jul 31, 2020	ER20-2594	VTransco	pending
Jul 30, 2020	ER20-2551	New England Power	pending
Jul 30, 2020	ER20-2553	NEP – LSA with MECO/Nantucket	pending
Jul 30, 2020	ER20-2572 ER21-1130	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 Jan 7, 2021	ER20-1839	VETCO	pending
Feb 26, 2020 Dec 11, 2020	ER20-1089	New England Elec. Trans. Corp.	pending
Feb 26, 2020 Dec 11, 2020	ER20-1088	New England Hydro Trans. Elec. Co.	pending
Feb 26, 2020 Dec 11, 2020	ER20-1087	New England Hydro Trans. Corp.	pending

[90] *The Conn. Light and Power Co.*, Docket No. ER21-651 (Feb. 10, 2021) (unpublished letter order).

[91] *Public Util. Trans. Rate Changes to Address Accumulated Deferred Income Taxes*, Order No. 864, 169 FERC ¶ 61,139 (Nov. 21, 2019), *reh'g denied and clarification granted in part,* 171 FERC ¶ 61,033 (Apr. 16, 2020) ("*Order 864*"). *Order 864* requires all public utility transmission providers with transmission rates under an OATT, a transmission owner tariff, or a rate schedule to revise those rates to account for changes caused by the 2017 Tax Cuts and Jobs Act ("2017 Tax Law"). Specifically, for transmission formula rates, *Order 864* requires public utilities (i) to deduct excess ADIT from or add deficient ADIT to their rate bases and adjust their income tax allowances by amortized excess or deficient ADIT; and (ii) to incorporate a new permanent worksheet into their transmission formula rates that will annually track ADIT information.

[92] *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*").

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

- ***ER21-1124 (FG&E).*** FG&E submits changes to its local service schedule (Sched. 21-FG&E) in light of the FERC's order approving RNS/LNS Rates and Rate Protocols Settlement Agreement II.[93]
- ***ER20-2133 (Versant Power).*** FERC issued a deficiency letter, directing Versant to provide within 30 days additional information related to its June 23, 2020 filing.
- ***ER21-1130 (TOs).*** TOs submit supplemental compliance filing to supplement their July 30 compliance filing (ER21-2572) in light of the FERC's order approving RNS/LNS Rates and Rate Protocols Settlement Agreement II.

XII. Misc. - Administrative & Rulemaking Proceedings

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

On March 2, 2021, the FERC issued a notice that a Commissioner-led technical conference will be convened electronically on April 29, 2021 to discuss electrification—the shift from non-electric to electric sources of energy at the point of final consumption (e.g., to fuel vehicles, heat and cool homes and businesses, and provide process heat at industrial facilities). The purpose is to "initiate a dialog between Commissioners and stakeholders on how to prepare for an increasingly electrified future." Specifically, the conference will address: projections, drivers, and risks of electrification in the US; the extent to which electrification may influence or necessitate additional transmission and generation infrastructure; whether and how newly electrified sources of energy demand (e.g., electric vehicles, smart thermostats, etc.) could provide grid services and enhance reliability; and the role of state and federal coordination as electrification advances. Individuals interested in participating as panelists should submit a self-nomination form by March 19, 2021 at: https://ferc.webex.com/ferc/onstage/g.php?MTID=e5e9ee76e4711c2f3a74fa036bab3a646. A supplemental notice will be issued prior to the conference with further details regarding the agenda and organization.

- **Resource Adequacy - Modernizing Electricity Mkt Design (Mar 23 tech conf) (AD21-10)**

On February 18, 2021, the FERC issued a notice that a Commissioner-led technical conference workshop will be convened electronically on March 23, 2021 to provide input to the Commission on resource adequacy in the evolving electricity sector. A supplemental notice with further details will be issued prior to the technical conference.

- **Office of Public Participation: Apr 16 Workshop (AD21-9)**

On February 22, 2021, the FERC issued a notice that a Commissioner-led workshop will be convened electronically on April 16, 2021 to provide input to the Commission on the creation of the Office of Public Participation. The Commission intends to establish and operate the Office of Public Participation to "coordinate assistance to the public with respect to authorities exercised by the Commission," including assistance to those seeking to intervene in Commission proceedings, pursuant to FPA section 319. The Commission plans to hear input on the following considerations in forming the Office of Public Participation, including: (1) the office's function and scope as authorized by FPA section 319; (2) the office's organizational structure and approach, including the use of equity assessment tools; (3) participation by tribes, environmental justice communities, and other affected individuals and communities, including those who have not historically participated before the Commission; and (4) intervenor compensation. Nominations for panelists to address each of these areas should be submitted on or before March 10, 2021 at: OPPWorkshopNominations@ferc.gov. A supplemental notice will be issued prior to the workshop with further details regarding the agenda, panelists, registration, and log-in information.

[93] *See supra* n. 21.

- **ISO/RTO Credit Principles and Practices (AD21-6)**

On February 25-26, 2021, the FERC held a technical conference to discuss principles and best practices for credit risk management in ISO/RTOs. Panel topics included: Credit Principles and Practices in ISOI/RTO Markets; RTO/ISO Comparison of Risk Management Structure, Credit Enhancements and Lessons Learned; Internal Resources and Expertise within RTOs/ISOs; Impact of Market Design on Credit Risk; Addressing Counterparty Risk: Minimum Participation Requirements and Know Your Customer Protocols; and Collateral, Initial and Variation Margining for FTR and non-FTR positions. Speaker materials are posted in the FERC's eLibrary.

Recall that, as previously reported, Energy Trading Institute[94] requested that the FERC hold a technical conference and conduct a rulemaking to update the requirements adopted in *Order 741*[95] and section 35.47 of the FERC's regulations addressing credit and risk management in the markets operated by ISO/RTOs. The FERC issued a notice of and received comments on ETI's request (AD20-6) in early 2020. The February technical conference was held, in part, in response to that request.

- **Offshore Wind Integration in RTOs/ISOs Tech Conf (Oct 27, 2020) (AD20-18)**

On October 27, 2020, the FERC convened a staff-led technical conference to consider whether and how existing RTO and ISO interconnection, merchant transmission and transmission planning frameworks can accommodate anticipated growth in offshore wind generation in an efficient or cost-effective manner that safeguards open access transmission principles. The conference also provided an opportunity for participants to discuss possible changes or improvements to the current regulatory frameworks that may accommodate such growth. Speaker materials and a transcript of the technical conference are posted in eLibrary. Since the last Report, Advanced Power Alliance filed comments requesting that the FERC issue a notice providing an opportunity for interested persons to submit post-conference comments and to thereafter "take action to facilitate transmission planning and interconnection policies that will enable construction of the cost-effective, efficient, resilient and environmentally-sound transmission infrastructure needed to connect new offshore wind generation to the onshore grid." This matter remains pending before the FERC.

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

On September 30, 2020, the FERC convened a Commissioner-led technical conference to discuss considerations related to state adoption of mechanisms to price carbon dioxide emissions, commonly referred to as carbon pricing, in regions with FERC-jurisdictional organized wholesale electricity markets. The September 30 conference was a response to (i) the April 14, 2020 request by Interest Parties,[96] who asserted that a technical conference "would be helpful to the Commission and stakeholders in the electric energy industry in deciding how best to move forward at the state and regional levels on these issues and in the relevant organized markets" complementing "state, regional, and national discussions currently taking place" as well as to (ii) the more than 30 sets of comments on the request that were filed. Speaker opening remarks (including those of Gordon van Welie,

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[94] 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."

[95] *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.

[96] "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.

Matt White, and other New England stakeholders), and comments are posted in eLibrary, as is a transcript of the conference.

Notice of Proposed Policy Statement. Following the technical conference, on October 15, 2020, the FERC issued a Notice of Proposed Policy Statement.[97] The FERC stated that the *Proposed Policy Statement* is "to clarify the Commission's jurisdiction over RTO/ISO market rules that incorporate a state-determined carbon price and to encourage RTO/ISO efforts to explore and consider the benefits of potential [FPA] section 205 filings to establish such rules." Specifically, the FERC proposed "to make it the policy of this Commission to encourage efforts by RTOs/ISOs and their stakeholders—including States, market participants, and consumers—to explore establishing wholesale market rules that incorporate state-determined carbon prices in RTO/ISO markets."[98] The FERC solicited comment on whether the following information and considerations it identified are "germane to the Commission's evaluation of a section 205 filing to determine whether an RTO/ISO's market rules that incorporate a state-determined carbon price in RTO/ISO markets are just, reasonable and not unduly discriminatory or preferential" or whether different or additional considerations may be or must be taken into account:

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

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

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

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

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

Comments on the *Proposed Policy Statement* were due by November 16, 2020 and were filed by, among others: NEPOOL, NESCOE, AEE, Brookfield, Calpine, Eversource, HQUS, LSP Power, MA AG, National Grid, NEPGA, and NRG. Reply comments were due by December 1, 2020, and were filed by 12 parties, including Covanta, Exelon, EPSA, NRG, the NYPSC. This matter is pending before the FERC.

- **Hybrid Resources (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 and a transcript of the technical conference have been posted to the FERC's eLibrary. Post-technical conference comments were filed by ISO-NE, CAISO, MISO, NYISO, PJM, Enel, American Council on Renewable Energy, AWEA, EEI, EPRI, R Street Institute, Savion, and SEIA.

On January 19, 2021, the FERC issued an order directing each ISO/RTO to submit, within 6 months (or before July 19, 2021), a report that provides: (a) a description of its current practices related to each of the following four hybrid resource issues: (1) terminology; (2) interconnection; (3) market participation; and (4) capacity valuation (collectively, the Issues); (b) an update on the status of any ongoing efforts to develop reforms

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

[98] *Id.* at P 15.

related to each of the Issues; and (c) responses to the specific requests for information contained in the order. Public comments in response to the RTO/ISO reports may be submitted within 30 days of the filing of the reports. The FERC will use the reports and comments to determine whether further action is appropriate.

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

On February 18, 2021, the FERC terminated this proceeding.[99] As previously reported, the FERC initiated this proceeding on January 8, 2018, (AD18-7)[100] and terminated a DOE NOPR rulemaking proceeding (RM18-1).[101] In terminating this proceeding, the FERC stated that it did not believe that generic action was appropriate[102] and "concerns about the resilience of the bulk power system are best addressed on a case-by-case and region-by-region basis."[103] The FERC committed to "work closely with RTOs, ISOs, and other public utilities to address grid resilience and take all appropriate actions to ensure that the electric grid remains reliable."[104]

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

On December 17, 2020, the FERC issued a NOPR[105] proposing to establish rules for incentive-based rate treatments for voluntary cybersecurity investments by a public utility for or in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission, and rates or practices affecting or pertaining to such rates for the purpose of ensuring the reliability of the Bulk-Power System. Comments on the *Cyber security Incentives NOPR* are due on or before April 6, 2021; reply comments, May 6, 2021.[106] Thus far, comments have been submitted jointly by aDolus Inc., Fortress Information Security, GMO GlobalSign Inc., Ion Channel, ReFirm Labs and Reliable Energy Analytics LLC; and George Cotter, Esq.

- **NOPR: Managing Transmission Line Ratings (RM20-16)**

On November 19, 2020, the FERC issued a NOPR[107] proposing to reform both the *pro forma* OATT and its regulations to improve the accuracy and transparency of transmission line ratings. Specifically, the NOPR proposes to require: transmission providers to implement ambient-adjusted ratings on the transmission lines over which they provide transmission service; ISO/RTOSs to establish and implement the systems and procedures necessary to allow transmission owners to electronically update transmission line ratings at least hourly; and transmission owners to share transmission line ratings and transmission line rating methodologies with their respective transmission provider(s) and, in ISO/RTOs, with their respective market monitor(s). Comments on the *Managing Transmission Line Ratings NOPR* are due on or before March 22, 2021.[108] Thus far, comments have been submitted by PacificCorp and New England State Agencies.[109]

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[99] *Grid Resilience in RTOs and ISOs*, 174 FERC ¶ 61,111 (Feb. 18, 2021) ("*Order Terminating Proceeding*").

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

[101] In terminating the DOE NOPR proceeding, the FERC concluded that the Proposed Rule and comments received did not support FERC action under Section 206 of the FPA, but did suggest the need for further examination by the FERC and market participants of the risks that the bulk power system faces and possible ways to address those risks in the changing electric markets.

[102] *Order Terminating Proceeding* at P 4.

[103] *Id.* at P 5.

[104] *Id.*

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

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

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

[108] The *Managing Transmission Line Ratings NOPR* was published in the *Fed. Reg.* on Jan. 21, 2021 (Vol. 86, No. 12) pp. 6,420-6,444.

[109] "New England State Agencies" are for purposes of this proceeding: CT Att'y Gen. William Tong, MA AG Maura Healey, the CT Dept. of Energy and Environ. Protection, the CT OCC, MOPA, NH OCA, Peter F. Neronha, RI AG, and Thomas J. Donovan, Jr., VT AG. The Feb 1 comments by the New England State Agencies broadly supported the FERC's proposals.

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

Still pending is the FERC's March 20, 2020 NOPR[110] proposing to revise its existing transmission incentives policy and corresponding regulations.[111] The proposed revisions include the following:

- ♦ A shift from risks and challenges to a ***consumers'' benefits test*** that focuses on ensuring reliability and reducing the cost of delivered power by reducing transmission congestion.
- ♦ ***ROEs incentive for Economic Benefits***. A 50-basis-point adder for transmission projects that meet an economic benefit-to-cost ratio in the top 75th percentile of transmission projects examined over a sample period and an additional 50-basis-point adder for transmission projects that demonstrate *ex post* cost savings that fall in the 90th percentile of transmission projects studied over the same sample period, as measured at the end of construction.
- ♦ ***ROE for Reliability Benefits***. A 50-basis-point adder for transmission projects that can demonstrate potential reliability benefits by providing quantitative analysis, where possible, as well as qualitative analysis.
- ♦ ***Abandoned Plant Incentive***. 100 percent of prudently incurred costs of transmission facilities selected in a regional transmission planning process that are cancelled or abandoned due to factors that are beyond the control of the applicant. Recovery from the date that the project is selected in the regional transmission planning process.
- ♦ ***Eliminate Transco Incentives***.
- ♦ ***RTO-Participation Inventive*****.** A 100-basis-point increase for transmitting utilities that turn over their wholesale facilities to an RTO, ISO, or Transmission Organization, and available regardless of whether participation is voluntary.
- ♦ ***Transmission Technologies Incentives***. Eligible for both a stand-alone, 100-basis-point ROE incentive on the costs of the specified transmission technology project and specialized regulatory asset treatment. Pilot programs presumptively eligible (though rebuttable).
- ♦ ***250-Basis-Point Cap***. Total ROE incentives capped at 250 basis points in place of current "zone of reasonableness" limit.
- ♦ ***Updated Date Reporting Processes***. Information to be obtained on a project-by-project basis, information collection expanded, updated reporting process.

A more detailed summary of the NOPR was distributed to the Transmission Committee and discussed at the TC's March 25, 2020 meeting. Over 80 sets of comments on the proposed revisions were filed on or before the July 1, 2020[112] 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 remains 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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[110] *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*, 170 FERC ¶ 61,204 (Mar. 20, 2020) ("*Electric Transmission Incentives NOPR*").

[111] 18 CFR 35.35 (2020).

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

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

On September 17, 2020, the FERC issued a final rule ("*Order 2222*")[113] adopting reforms to remove what it found were barriers to the participation of distributed energy resource ("DER")[114] aggregations in the RTO/ISO markets. *Order 2222* requires each RTO/ISO to revise its tariff to ensure that its market rules facilitate the participation of DER aggregations. Specifically, the tariff provisions addressing DER aggregations must:

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

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

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

(4) address locational requirements for DER aggregations;

(5) address distribution factors and bidding parameters for DER aggregations;

(6) address information and data requirements for DER aggregations;

(7) address metering and telemetry requirements for DER aggregations;

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

(9) address modifications to the list of resources in a DER aggregation;

(10) address market participation agreements for DER aggregators; and

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

Each RTO/ISO must file the tariff changes needed to implement the requirements of *Order 2222* on or before July 19, 2021.[115] 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 DERs, it must demonstrate on compliance that its existing approach meets *Order 2222*'s requirements. Requests for extension of time to comply with *Order 2222* have been filed by MISO, SPP and PJM. Those requests are pending before the FERC.

Requests for Rehearing Denied by Operation of Law. Requests for clarification and/or rehearing of *Order 2222* were filed by Excel Energy Services, the Kansas Corporation Commission, AEE and AEMA, and Public Interest

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

[114] 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."

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

Organizations.[116] On November 19, 2020, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[117] The Notice confirmed that the 60-day period during which a petition for review of *Order 2222* can be filed with an appropriate federal court was triggered when the FERC did not act on the requests for rehearing of *Order 2222*. 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."

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

As previously reported, *Order 860,*[118] issued three years after the FERC's *Data Collection NOPR,*[119] (i) revises the FERC's MBR regulations by establishing a relational database of ownership and affiliate information for MBR Sellers (which, among other uses, will be used to create asset appendices and indicative screens), (ii) reduces the scope of information that must be provided in MBR filings, modifies the information required in, and format of, a MBR Seller's asset appendix, (iii) changes the process and timing of the requirements to advise the FERC of changes in status and affiliate information, and (iv) eliminates the requirement adopted in *Order 816* that MBR Sellers submit corporate organization charts. In addition, the FERC stated that it will *not* adopt the *Data Collection NOPR* proposal to collect Connected Entity data from MBR Sellers and entities trading virtuals or holding FTRs. The FERC will post on its website high-level instructions that describe the mechanics of the relational database submission process and how to prepare filings that incorporate information that is submitted to the relational database. As recently extended (*see* below), *Order 860* will become effective April 1, 2021, and submitters will have until close of business on August 2, 2021 to make their initial baseline submissions. Submitters will be required to obtain in Spring 2021 FERC-generated IDs for reportable entities that do not have CIDs or LEIs, as well as Asset IDs for reportable generation assets without an EIA code so that every ultimate upstream affiliate or other reportable entity has a FERC-assigned company identifiers ("CID"), Legal Entity Identifier,[120] 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,[121] 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

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

[117] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Indep. Sys. Operators*, 173 FERC ¶ 62,090 (Nov. 19, 2020).

[118] *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).

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

[120] 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.

[121] *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*").

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.

March 25, 2021 Technical Workshop. On February 25, 2021, the FERC issued a notice of a technical workshop to discuss the functionality and features of the MBR Database. The workshop will be held electronically on March 25, 2021 from 10 a.m. to 3 p.m. The FERC will issue a supplemental notice prior to the workshop with further details regarding the agenda. Individuals who are interested in registering for the conference can do so here: https://ferc.webex.com/ferc/j.php?MTID=e6dd18def200b281ff165e57325102ee0.

- **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").[122] 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."[123] Comments on the *NAESB WEQ v. 003.3 Standards NOPR* were due on or before November 3, 2020[124] and were filed by Bonneville Power Administration ("BPA"), EEI, the IRC, and Open Access Technology International. The *NAESB WEQ v. 003.3 Standards NOPR* is pending before the FERC.

- **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.[125] 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.

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

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

[124] 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.

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

2. *Form of Filing*. When the entity requesting remedial relief is the entity that acted (or believes it may have acted) in a manner inconsistent with the tariff, such requests should be filed as petitions for declaratory order under Rule 207 of the FERC's Rules of Practice and Procedure. When the filing entity alleges a different entity has acted in a manner inconsistent with the tariff, such requests should be filed as complaints under Rule 206. Given the filing fees associated with petitions for declaratory order, the industry was encouraged to directly address this aspect of the proposal.

3. *Expressly Request FERC Action pursuant to FPA section 309 or NGA section 16.4*. These provisions have been found to afford the FERC the latitude to remedy past non-compliance "provided the agency's action conforms with the purposes and policies of Congress and does not contravene any terms of the Act."

The FERC acknowledged that this Policy would represent a change from its past approach, particularly in situations where inadvertent failures to comply with ministerial tariff requirements have not been protested. The FERC suggested a few ways tariffs may be modified to avoid what may appear by comparison to be harsh outcomes, including expressly stating in the tariff that a failure to comply with a certain deadline may be waived by order of the FERC or by allowing various kinds of errors to be cured within a reasonable period of time after a default has occurred or an error has been discovered, but is difficult to imagine how feasible or how well these options might work in practice.

The FERC proposed to incorporate its current four-part analysis[126] 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,[127] 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,[128] INGAA, Kansas Electric Power Coop. ("KEPC"), NGA, NGSA, NRECA, Public Citizen, Sunflower Electric Power, and TAPS. Reply comments were filed

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[126] 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.

[127] *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.

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

by APPA, Joint Trade Associations,[129] 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*.[130] 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").[131] In addition, the FERC clarified its policies governing the formation of proxy groups and the treatment of outliers in proceedings addressing natural gas and oil pipeline ROEs. Finally, the FERC encouraged oil pipelines to file revised FERC Form No. 6, page 700s for 2019 reflecting the revised ROE policy. This Policy Statement became effective May 27, 2020.[132] 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[133] answered the New England TO's May 10 supplemental comments. On June 15, 2020, Joint Parties[134] 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.[135] 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)**

Since the last Report, on February 18, 2021, the FERC issued a new notice of inquiry ("NOI") in which it seeks new information and additional stakeholder perspectives to help it explore whether it should revise its approach under the currently effective policy statement on the certification of new natural gas transportation

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

[130] *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*").

[131] 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.[131] The FERC also sought comment on whether any changes to its policies concerning public utility ROEs should be applied to interstate natural gas and oil pipelines. This NOI followed *Emera Maine*, which reversed *Opinion 531*, and seeks to engage interests beyond those represented in the *Emera Maine* proceeding (see EL11-66 *et al.* in Section I above).

[132] 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.

[133] 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.

[134] "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.

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

facilities to determine whether a proposed natural gas project is or will be required by the public convenience and necessity, as that standard is established in section 7 of the Natural Gas Act.[136] The 2021 NOI is to provide an opportunity for stakeholders to refresh the record and provide updated information and additional viewpoints to help the FERC assess its policy.[137] The FERC strongly urged stakeholders to not resubmit previously filed comments, which remain in the record of this proceeding.[138] Comments on the 2021 NOI are due on or before April 26, 2021.[139]

XIII. Natural Gas Proceedings

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

- **New England Pipeline Proceedings**
  The following New England pipeline projects are currently under construction or before the FERC:
  - ***Iroquois ExC Project (CP20-48)***
    - 125,000 Dth/d of incremental firm transportation service to ConEd and KeySpan by building and operating new natural gas compression and cooling facilities at the sites of four existing Iroquois compressor stations in Connecticut (Brookfield and Milford) and New York (Athens and Dover)
    - Three-year construction project; service request by November 1, 2023
    - February 2, 2020 application for a certificate of public convenience and necessity pending; Iroquois requests on Jan 26, 2021 that the FERC act promptly and issue the certificate
  - ***Atlantic Bridge Project (CP16-9)***
    - On February 24, 2020, the FERC authorized Algonquin Gas Transmission, LLC ("Algonquin") and Maritimes & Northeast Pipeline, LLC ("Maritimes") to place facilities associated with the Atlantic Bridge Project into service.[140] Rehearing of the Authorization Order was timely requested, but denied by operation of law.
    - In a fairly unprecedented order issued February 18, 2021,[141] the FERC, expressing concerns regarding operation of the project, established briefing on the following matters:
      - In light of the concerns expressed regarding public safety, is it consistent with the FERC's responsibilities under the Natural Gas Act ("NGA") to allow the Weymouth Compressor Station to enter and remain in service?
      - Should the Commission reconsider the current operation of the Weymouth Compressor Station in light of any changed circumstances since the project was authorized? For example, are there changes in the Weymouth Compressor Station's projected air emissions impacts or public safety impacts the Commission

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

137 *Id.* at P 3.

138 The 2021 NOI follows an April 19, 2018 NOI that sought comments 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. Literally thousands of individual and mass-mailed comments were filed on the 2018 NOI.

139 The 2021 NOI was published *Fed. Reg.* on Feb. 24, 2021 (Vol. 86, No. 35) pp. 11,268-11,274.

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

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

should consider? We encourage parties to address how any such changes affect the surrounding communities, including environmental justice communities.
- Are there any additional mitigation measures the Commission should impose in response to air emissions or public safety concerns?
- What would the consequences be if the Commission were to stay or reverse the Authorization Order?

- Initial briefs are due April 5, 2021; reply briefs, May 5, 2021.
- The FERC noted that the facilities placed in service pursuant to the Authorization Order may remain in service while it considers the issues set for briefing.

- **Non-New England Pipeline Proceedings**
The following pipeline projects could affect ongoing pipeline proceedings in New England and elsewhere:

  - **Northern Access Project (CP15-115)**
    - The New York State Department of Environmental Conservation ("NY DEC") and the Sierra Club requested rehearing of the *Northern Access Certificate Rehearing Order* on August 14 and September 5, 2018, respectively. On August 29, National Fuel Gas Supply Corporation and Empire Pipeline ("Applicants") answered the NY DEC's August 14 rehearing request and request for stay. On April 2, 2019, the FERC denied the NY DEC and Sierra Club requests for rehearing.[142] 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*.[143] 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,[144] 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.[145] 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

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

[143] *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).

[144] 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).

[145] *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*").

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.[146] On February 2, 2019, the 2nd Circuit vacated the decision of the NY DEC and remanded the case with instructions for the NY DEC to more clearly articulate its basis for the denial and how that basis is connected to information in the existing administrative record. The matter is again before the NY DEC.

- On November 26, 2018, the Applicants filed a request at FERC for a 3-year extension of time, until February 3, 2022, to complete construction and to place the certificated facilities into service. The Applicants cited the fact that they "do not anticipate commencement of Project construction until early 2021 due to New York's continued legal actions and to time lines required for procurement of necessary pipe and compressor facility materials." The extension request was granted on January 31, 2019.
- On August 8, 2019, the NY DEC again denied Applicants request for a Water Quality Certification, and as directed by the Second Circuit,[147] 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.[148]
- On October 16, 2020, Applicants requested, due to ongoing legal and regulatory delays, an additional 2-year extension of time, until December 1, 2024, to complete construction of the Project and enter service. More than 50 sets of comments on the requested extension were filed and on December1, 2020, the FERC dismissed, without prejudice, Applicants' request for an extension of time, [149] finding the request premature. The FERC reiterated its encouragement that pipeline applicants requesting extensions "file their requests no more than 120 days before the deadline to complete construction", so that the FERC has the relevant information available to determine whether good cause exists to grant an extension of time and whether the FERC's prior findings remain valid.[150]

- **Natural Gas-Related Enforcement Actions**

Freeport LNG (IN21-7). On January 28, 2021, the FERC approved a Stipulation and Consent Agreement ("Agreement") with Freeport LNG Development L.P. ("Freeport LNG")[151] that resolved OE's investigation into whether Freeport LNG violated Section 3(e) of the Natural Gas Act ("NGA") (15 U.S.C. § 717b(e) (2012)) and the FERC's Order in *Freeport LNG Dev., L.P.*, 148 FERC ¶ 61,076 (2014) ("*Freeport Order*"). Enforcement determined that Freeport (i) violated NGA Section 3(e) and the *Freeport Order* when its contractor engaged in clearing and stabilization activities on 75, rather than 50, acres as authorized in the *Freeport Order* and (ii) violated the *Freeport Order* when it failed to fully and accurately describe the known violation on its site (providing statements in its Bi-Weekly Construction Reports that were inconsistent with materials gathered as part of an internal investigation). Under the Agreement, in which Freeport LNG neither admits nor denies the

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

[147] 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).

[148] *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).

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

[150] *Id.* at P 10.

[151] *Freeport LNG Dev., L.P.*, 174 FERC ¶ 61,055 (Jan. 28, 2021).

alleged violations, Freeport LNG must ***pay a $500,00 civil penalty*** to the United States Treasury. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

Tres Palacios (IN21-3). On January 19, 2021, the FERC approved a Stipulation and Consent Agreement ("Agreement") with Tres Palacios LLC ("Tres Palacios")[152] that resolved OE's investigation into whether Tres Palacios violated Section 7(e) of the NGA related to its failure to timely conduct sonar surveys as required by the FERC's 2007 *Tres Palacios Certificate Order*.[153] Enforcement determined that sonar surveys required under the *Certificate Order* were not undertaken within the time frame required and Tres Palacios failed to seek an extension of time to comply until faced with an inquiry into its non-compliance. Under the Agreement, in which Tres Palacios neither admits nor denies the alleged violations, Tres Palacios must ***pay a $700,00 civil penalty*** to the United States Treasury. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

BP (IN13-15). On December 17, 2020, the FERC issued *Opinion 549-A*,[154] a 159-page decision addressing arguments raised on rehearing requested of *Opinion 549.*[155] *Opinion 549-A* modifies the discussion in *Opinion 549*, but reaches the same the result (ultimately requiring BP to pay a ***$20.16 million civil penalty (roughly $24.4 million with accrued interest) and disgorge $207,169***). Of note, *Opinion 549-A* denied BP's motion to dismiss this enforcement action as time barred (by the five-year statute of limitations set forth in 28 U.S.C. § 2462), finding BP waived any statute of limitations defense by failing to raise it earlier in this proceeding.[156] Opinion 549-A revised Ordering Paragraph (C) to direct the disgorged profits to non-profits that disburse the Low Income Home Energy Assistance Program of Texas funds, rather than to the Texas Department of Housing.[157]

On December 29, BP filed a notice that it intends to appeal *Opinion 549-A* to the Fifth Circuit Court of Appeals and paid the civil penalty amount on December 28, 2020, under protest and with full reservation of rights pending the outcome of judicial review of that Opinion. On January 19, BP filed a notice that it disgorged $250,295 ($207,169 principal plus interest), divided equally ($83,431.67) among the following 3 entities identified in the "2016 Comprehensive Energy Assistance Program Subrecipient List": Dallas County Dept. of Health and Human Services (serving Dallas); El Paso Community Action, Project Bravo (Serving El Paso); and Panhandle Community Services (serving Armstrong and numerous other counties), again under protest and with full reservation of rights pending the outcome of judicial review of *Opinion 549/549-A*.

Total Gas & Power North America, Inc. et al. (IN12-17). On April 28, 2016, the FERC issued a show cause order[158] 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

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152 *Tres Palacios LLC*, 174 FERC ¶ 61,060 (Jan. 19, 2021).

153 *Tres Palacios Gas Storage LLC*, 120 FERC ¶ 61,253 (2007) ("*Tres Palacios Certificate Order*").

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

155 *BP America Inc.*, Opinion No. 549, 156 FERC ¶ 61,031 (July 11, 2016) ("*BP Penalties Order*") (affirming Judge Cintron's Aug. 13, 2015 Initial Decision finding that BP America Inc., BP Corporation North America Inc., BP America Production Company, and BP Energy Company (collectively, "BP") violated Section 1c.1 of the FERC's regulations ("Anti-Manipulation Rule") and NGA Section 4A (*BP America Inc.et al,* 152 FERC ¶ 63,016 (Aug. 13, 2015) ("*BP Initial Decision*")).

156 *BP Penalties Allegheny Order* at P 1.

157 *Id*. at P 319.

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

a scheme to manipulate the price of natural gas at four locations in the southwest United States between June 2009 and June 2012.[159]

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.

XIV. State Proceedings & Federal Legislative Proceedings

- **New England States' Vision Statement**

In October 2020, the six New England states released their "Vision Statement", outlining their vision for "a clean, affordable, and reliable 21st century regional electric grid" and committing to engage in a collaborative and open process, supported by NESCOE, intended to advance the principles discussed in the Vision Statement. As part of that effort, a series of online technical forums to discuss the issues presented in the Vision Statement have been held or announced by certain State Agencies.[160] Thus far, the following on-line technical forums have been held:

Jan 13, 2021	Wholesale Market Reform
Jan 25, 2021	Wholesale Market Reform
Feb 2, 2021	Transmission Planning
Feb 25, 2021	Governance Reform

Written comments on the topics and discussions addressed in the Governance Reform Wholesale Market Reform forums are due by March 26, 2021 and may be submitted at **WholesaleEnergy@NewEnglandEnergyVision.com**. Written comments will be posted publicly on this website after this deadline.

Recordings of the technical forums, as well as draft notices, agendas, and additional information on these sessions, are available on the New England States' Vision Statement website (https://newenglandenergyvision.com/). Details on an evening forum related to environmental justice issues has yet to be announced.

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159 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.

160 "State Agencies" jointly announcing the technical forums are identified as: CT DEEP, ME Governor's Energy Office, MA Executive Office of Energy and Environmental Affairs, NH PUC, RI Office of Energy Resources, and VT DPS.

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).

- **Exelon PP-10 Complaint (20-1509)**
  Underlying FERC Proceeding: EL20-52[161]
  Petitioner: Exelon

On December 18, 2020, Constellation Mystic Power, LLC ("Exelon") petitioned the DC Circuit Court of Appeals for review of the FERC's orders denying Exelon's PP-10 Complaint and the denial of its request for rehearing of the *Order Denying PP-10 Complaint*.[162] Appearances were due January 22, 2021. ISO-NE, NESCOE, CT PURA, MMWEC, and Vistra/Dynegy moved to intervene. On January 21, Exelon filed a docketing statement and statement of issues to be raised. On January 22, the FERC moved for a 60-day interval between Exelon's Opening Brief and its Answering Brief. On February 16, 2021, Exelon moved to voluntarily dismiss its Petition. Its motion was unopposed, and the Court dismissed the case and issued a mandate to the FERC on February 18, 2021, ending this proceeding.

- **ISO-NE Implementation of Order 1000 Exemptions for Immediate Need Reliability Projects (20-1422)**
  Underlying FERC Proceeding: EL19-90[163]
  Petitioner: LS Power

On October 16, 2020, LSP Transmission Holdings II, LLC ("LS Power") petitioned the DC Circuit Court of Appeals for review of the FERC's orders addressing ISO-NE's implementation of the Order 1000 exemptions for immediate need reliability projects. Since the last Report, and after the Clerk granted extensions of time to file procedural and dispositive motions, the FERC on December 10, 2020 requested at least 60 days between the filing of LS Power's opening brief and the FERC's brief in response, and on December 28, 2020, filed a certified index to the record. On December 29, 2020, the Court granted the motions to intervene by Avangrid and MMWEC.

On March 2, 2021, the Court at FERC's request, issued an amended briefing schedule to apply in this case, adding roughly one month to each deadline previously identified: Petitioner's Brief due April 5, 2021; Intervenors in Support of Petitioners Brief, April 1215, 2021; FERC's brief, June 11, 2021; Intervenors in Support of FERC, July 9, 2021; Petitioner's Reply Brief, July 9, 2021; Intervenors in Support of Petitioner Reply Brief, July 9, 2021; Deferred Appendix, July 16, 2021; and Final Briefs July 30, 2021.

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

162 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"), 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.

163 *ISO New England Inc., 171 FERC ¶ 61,211 (June 18, 2020) ("Order Terminating Proceeding") (finding (i) "insufficient evidence in the record to find under FPA section 206 that [ISO-NE's] implementation of the exemption for immediate need reliability projects is unjust, unreasonable, or unduly discriminatory or preferential; (ii) "insufficient evidence in the record to find that ISO-NE implemented the immediate need reliability project exemption in a manner that is inconsistent with or more expansive than [the FERC] directed"; and (iii) that ISO-NE complies with the five criteria established for the immediate need reliability project exemption); and ISO New England Inc., 172 FERC ¶ 61,293 (Sep. 29, 2020) ("Order 1000 Exemptions Allegheny Order")* (addressing arguments raised by request for rehearing denied by operation of law, modifying discussion in *Order Terminating Proceeding,* but reaching same result).

- **CIP IROL Cost Recovery Rules (20-1389)**
  Underlying FERC Proceeding: ER20-739[164]
  Petitioner: Cogentrix, Vistra

On September 25, 2020, Cogentrix and Vistra petitioned the DC Circuit Court of Appeals for review of the FERC's orders allowing for recovery of expenditures to comply with the IROL-CIP requirements, but only those costs incurred on or after the effective date of the relevant individual FPA section 205 filing, including undepreciated costs of any such past capital expenditures to comply with the IROL-CIP requirements. On December 22, 2020, the Court adopted a proposed *revised* briefing schedule that added roughly 45 days to each procedural deadline previously established. On March 1, 2021, Cogentrix and Vistra filed Petitioners' Brief. Next up are FERC's Respondent Brief (April 30, 2021); Intervenor for Respondent Brief (June 1, 2021); Petitioners' Reply Briefs (June 28, 2021); Deferred Appendix (July 16, 2021); and Final Briefs (July 26, 2021).

- **Mystic 8/9 Cost of Service Agreement (20-1343; 20-1361, 20-1362; 20-1365, 20-1368; 21-1067; 21-1070)(consolidated)**
  Underlying FERC Proceeding: EL18-1639[165]
  Petitioners: Mystic (20-1343), NESCOE (20-1361, 21-1067), MA AG (20-1362), CT Parties (20-1365, 20-1368, 21-1070)

Mystic, NESCOE, MA AG, and CT Parties have separately petitioned the DC Circuit Court of Appeals for review of the FERC's orders addressing the COS Agreement among Mystic, ExGen and ISO-NE.166 The cases have been consolidated into Case No. 20-1343. Since the last Report, on February 17 and 24, 2021, the Court consolidated with 20-1343 the most recent appeals in cases 21-1067 (NESCOE) and 21-1070 (CT Parties), respectively. On February 26, 2021, the FERC filed a motion indicating that this case can return to the Court's active docket and its anticipation that it will file a proposed briefing schedule in this consolidated case.

- ***CASPR* (20-1333, 20-1331) (consolidated)****
  Underlying FERC Proceeding: ER18-619[167]
  Petitioners: Sierra Club, NRDC, RENEW Northeast, and CLF

On August 31, 2020, the Sierra Club, NRDC, RENEW Northeast, and CLF petitioned the DC Circuit Court of Appeals for review of the FERC's order accepting ISO-NE's CASPR revisions (which, under *Allegheny*, is ripe for review). On October 2, 2020, appearances, docketing statements, a statement of issues to be raised, and a statement of intent to utilize deferred joint appendix were filed. On October 19, 2020, the FERC moved to dismiss the case for a lack of jurisdiction (arguing that Petitioners missed their opportunity to timely file their Petition for review in 2018, and filing within 60 days of *Allegheny* did not make their Petition timely). Alternatively, the FERC asked that the case be held in abeyance for 60 days pending issuance of a further FERC order on this matter. On October 29, Petitioners opposed the FERC's motion. On November 5, 2020, the FERC filed a reply, indicated that an order on rehearing would be issued imminently and suggested that, if the Court declines to dismiss the petition, it should be held in abeyance until the Commission issues an order on rehearing. As noted above, the FERC issued the *CASPR Allegheny Order* on November 19, modifying the discussion in the *CASPR Order*, but reaching the same the result. The Sierra Club, NRDC and CLF also requested rehearing of the November 19 order.

On January 12, 2021, the Court dismissed as moot the FERC's October 19 motion to hold this proceeding in abeyance and ordered that the motion to dismiss be referred to the merits panel (Judges Pillard, Katsas and

[164] *ISO New England Inc.*, 171 FERC ¶ 61,160 (May 26, 2020) ("*CIP IROL Cost Recovery Order*") and *ISO New England Inc.*, 172 FERC ¶ 61,251 (Sep. 17, 2020) ("*CIP IROL Allegheny Order*", and together with the CIP IROL Cost Recover Order, the "*CIP IROL Orders*").

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

[166] 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.

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

Walker) and addressed by the parties in their briefs. On January 25 and 26, CT Parties and MMWEC and NHEC filed statements of issues and notices that they intend to participate in support of Petitioners. On January 27, the Court ordered the parties to submit by February 26, 2021, proposed formats for the briefing of these cases.

Since the last Report, NEPOOL moved for leave to intervene in this case. In addition, on February 26, 2021, the parties submitted a proposed briefing format and the FERC submitted a motion request 60 days between the submission of Petitioners' opening brief and its brief in response.

- ***Opinion 531-A* Compliance Filing Undo (20-1329)**
  Underlying FERC Proceeding: ER15-414[168]
  Petitioners: TOs' (CMP et al.)

On August 28, 2020, the TOs[169] 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*[170] decision. On September 22, 2020, the FERC submitted an unopposed motion to hold this proceeding in abeyance for four months to allow for the Commission to "a future order on petitioners' request for rehearing of the order challenged in this appeal, and the rate proceeding in which the challenged order was issued remains ongoing before the Commission." On October 2, 2020, the Court granted the FERC's motion, and directed the parties to file motions to govern future proceedings in this case by February 2, 2021. On January 25, 2021, the FERC requested that the Court continue to hold this petition for review in abeyance for an additional three months, with parties to file motions to govern future proceedings at the end of that period. The FERC requested continued abeyance because of its intention to issue a future order on petitioners' request for rehearing of the order challenged in this appeal, and the rate proceeding in which the challenged order was issued remains ongoing before the FERC. Petitioners consented to the requested abeyance. On February 11, 2021, the Court issued an order that that this case remain in abeyance pending further order of the court and directed the parties to file motions to govern future proceedings in this case by April 26, 2021.

- **2013/14 Winter Reliability Program Order on Compliance and Remand (20-1289, 20-1366) (consol.)**
  Underlying FERC Proceeding: ER13-2266[171]
  Petitioner: TransCanada

On July 30, 2020, TransCanada Power Marketing ("Petitioner" or "TransCanada") again petitioned the DC Circuit Court of Appeals for review of the FERC's action on the 2013/2014 Winter Reliability Program, this time in the FERC's April 1, 2020 *2013/14 Winter Reliability Program Order on Compliance and Remand*.[172] NEPGA intervened on October 15, 2020 (and its intervention granted on October 28). On October 16, TransCanada filed a docketing statement and statement of issues. On October 29, the FERC filed a certified index to the record and an unopposed motion for a 60-day briefing period. On December 2, 2020, the Court granted the FERC's October 29 motion On January 11, 2021, TransCanada submitted its initial brief. Respondent Brief of FERC is due Mach 12, 2021; Intervenors' Joint Brief in Support of Respondent, March 19, 2021; Petitioners' Reply Briefs, April 9, 2021; the Deferred Appendix, April 16, 2021; and Final Briefs, April 30, 2021.

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

[169] 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.

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

[171] 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*").)

[172] In TransCanada, the DC Circuit granted TransCanada's prior petition in part, and directed the FERC to either better justify its determination or revise its disposition to ensure that the rates under the Program are just and reasonable. *TransCanada* at 1.

- **ISO-NE's Inventoried Energy Program (Chapter 2B) Proposal (19-1224***; 19-1247; 19-1252; 19-1253)(consolidated); Underlying FERC Proceeding: ER19-1428**[173]
  Petitioners: ENECOS (Belmont et al.) (19-1224); MA AG (19-1247); NH PUC/NH OCA (19-1252); Sierra Club/UCS (19-1253)

As previously reported, at the unopposed request of the FERC, the Court issued an order suspending the previous briefing schedule and remanding the record back to the FERC. Subsequently, the FERC issued its *IEP Remand Order* (June 18, 2020) and its Notice of Denial by Operation of Law of the requests for rehearing of its *IEP Remand Order* (August 20, 2020). As previously reported, each of the Petitioners filed amended petitions for review in the consolidated proceeding in order to bring the FERC's *IEP Remand Order* and the post-remand FERC record before the DC Circuit. On November 10, the Court ordered that the cases be removed from abeyance and set a revised briefing schedule that called for the following: Petitioners' Opening Briefs (December 11, 2020); Respondent Brief of FERC (February 9, 2021); Intervenors' Joint Brief in Support of Respondent (February 16, 2021); Petitioners' Reply Briefs (March 30, 2021); Deferred Appendix (April 20, 2021); and Final Briefs (May 4, 2021). Opening Briefs from Petitioners were filed on December 11, 2020. Since the last Report, the FERC filed its Respondent Brief on February 9. Intervenor for Respondent Briefs were filed on February 16 by ISO-NE and NEPGA. On February 24, the FERC filed an amended certified index to the record. Next up will be Petitioners' Reply Briefs.

Other Federal Court Activity of Interest

- ***Order 872* (20-72788,* 21-70113; 20-73375, 21-70113) (consol.) (9th Cir.)**
  Underlying FERC Proceeding: RM19-15[174]
  Petitioners: SEIA et al.

On September 17, 2020, SEIA petitioned the 9th Circuit Court of Appeals for review of *Order 872*.[175] On October 9, the FERC filed an unopposed motion for the Court to hold this appeal in abeyance, suspend filing of the certified index to the record, and issue a new briefing schedule after January 4, 2021. The abeyance will permit the FERC to address the pending rehearing requests in a future order. On October 26, 2020, the Court granted the FERC's motion. On January 29, 2021, SEIA requested that this case be consolidated with the others, and that the abeyance period be extended to give the parties additional time to coordinate and develop a unified, efficient briefing schedule. Since the last Report, on February 8, 2021, the Court granted the motion to consolidate and the motion to continue to hold these petitions in abeyance. The Court directed petitioners to file a status report on or before April 9, 2021.

- **PennEast Project (18-1128)**
  Underlying FERC Proceeding: CP15-558[176]
  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")[177] for the construction and operation of a new 116-mile natural gas pipeline from Luzerne County, Pennsylvania, to Mercer County, New Jersey, along

173 162 FERC ¶ 61,127 (Feb. 15, 2018) ("*Order 841*"); 167 FERC ¶ 61,154 (May 16, 2019) ("*Order 841-A*").

174 *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).

175 *Order 872* approved pricing and eligibility revisions to the FERC's long-standing regulations implementing sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA"), including: state flexibility in setting QF rates; a decrease (to 5 MW) to the threshold for a rebuttable presumption of access to nondiscriminatory, competitive markets; updates to the "One-Mile Rule"; clarifications to when a QF establishes its entitlement to a purchase obligation; and provision for certification challenges.

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

177 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.

with three laterals extending off the mainline, a compression station, and appurtenant above ground facilities ("PennEast Project"). The cases are being held in abeyance "pending final disposition of any post-dispositional proceedings [ ] before the United States Supreme Court resulting from the Third Circuit's decision in No. 19-1191 (In re: PennEast Pipeline Company, LLC (3rd Cir. Sep. 10, 2019)), or other action that resolves the obstacle PennEast poses". That decision held that the Eleventh Amendment barred condemnation cases brought by PennEast in federal district court in New Jersey to gain access to property owned by the State or its agencies, thus calling into question the viability of PennEast's proposed project route, and the certificates issued in the underlying case. Until the Third Circuit case is resolved, which is in the midst of proceedings before the Supreme Court, the DC Circuit will not take up this case. The last Joint Status Report was filed on December 23, 2020, noting developments since the September 28, 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, 20-1182, 20-1240, 20-1241, 20-1248, 20-1251, 20-1267, 20-1513)**
  Underlying FERC Proceeding: EL14-12; EL15-45[178]
  Petitioners: MISO TOs, Transource Energy, Dec 23 Petitioners et al.

The MISO Transmission Owners (TOs), Transource and "Dec 23 Petitioners",[179] among others, have appealed *Opinion 569/569-A*. The MISO TOs' case has been consolidated with previous appeals that had been held in abeyance, with the lead case number assigned as 16-1325. Since the last Report, the FERC filed a certified Index to the Record (December 3), the Parties filed a joint unopposed briefing schedule (December 23) and First Energy moved to voluntarily dismiss the cases it initiated (20-1227 & 20-1275), which the Court granted on January 5, 2021. The Court also consolidated case no. 20-1513 (filed by Dec 23 Petitioners) with the lead case (16-1325).

On February 2, 2021, the Court issued a revised briefing format and schedule to apply in these consolidated cases: Statement of issues due February 8, 2021; Petitioners' Briefs, March 10, 2021; Intervenors in Support of Petitioners Briefs and Amici Curiae Briefs, March 24, 2021; FERC's brief, June 8, 2021; Intervenors in Support of FERC, June 22, 2021; Petitioners Reply Briefs, July 8, 2021; Intervenors in Support of Petitioners Reply Briefs, July 22, 2021; Joint Deferred Appendix, August 6, 2021; and Final Briefs, August 19, 2021. Since the last Report, Statements of issues were filed on February 8, 2021. Next up are Briefs from Petitioners, Intervenors in Support of Petitioners, and Amici Curiae.

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[178] *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).

[179] "Dec 23 Petitioners" are: Assoc. of Bus. Advocating Tariff Equity; Coalition of MISO Transmission Customers: IL Industrial Energy Consumers; IN Industrial Energy Consumers, Inc.; MN Large Industrial Group; WI Industrial Energy Group; AMP; Cooperative Energy; Hoosier Energy Rural Elec. Coop.; MS Public Service Comm.; MO Public Service Comm.; MO Joint Municipal Electric Utility Comm.; Organization of MISO States, Inc.; Southwestern Elec. Coop., Inc.; and Wabash Valley Power Assoc.

INDEX
Status Report of Current Regulatory and Legal Proceedings as of March 3, 2021

COVID-19

I. Complaints/Section 206 Proceedings

II. Rate, ICR, FCA, Cost Recovery Filings

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

IV. OATT Amendments/Coordination Agreements

V. Financial Assurance/Billing Policy Amendments

VI. Schedule 20/21/22/23 Updates

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

IX. Membership Filings

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

XI. Misc. Regional Interest

XII. Misc: Administrative & Rulemaking Proceedings

XIII. Natural Gas Proceedings

XIV. State Proceedings & Federal Legislative Proceedings

XV. Federal Courts

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Dave Cavanaugh, Participants Committee Chair

DATE: February 25, 2021

RE: Discussion of NEPOOL Audits

There are two reasons for this memo: (1) to determine whether there is any interest in an audit this year of ISO-NE performance that is not already being planned; and (2) to advise you that the Budget and Finance Subcommittee will review ISO's planned and completed audits, rather than reconstituting the NEPOOL Audit Management Subcommittee (NAMS) for that purpose.

NEPOOL members, acting through the Participants Committee, have the right to request an independent performance audit in addition to the audits, both independent and internal, that the ISO does of its finances and operations. Specifically, Section 15.1 of the Participants Agreement (Performance Audits) provides in part as follows:

> At the request of the Participants Committee, ISO shall engage an independent third party to be chosen by mutual agreement of ISO and the Participants Committee to conduct a periodic audit of ISO's performance and shall cooperate fully in the conduct of such audits. Such audits shall be conducted at such intervals as shall be determined by the Participants Committee, but no more frequently than every three years unless a specified issue has been identified for audit by the Participants Committee and ISO.

In years past, NEPOOL had requested a number of independent audits pursuant to these rights,[1] but it has been nearly five years since there has any interest among NEPOOL members in augmenting any of the audits the ISO already performs. Over time, the ISO had expanded the audits of its performance, both internally and with independent auditors, now reflecting a three-pronged audit strategy: an annual SSAE 18 engagement (SOC 1) performed by an external audit firm, market system certifications performed by an independent third party, and coverage provided by the Internal Audit Department (IAD). Attached for your information is a listing of the ISO's planned audits for 2021. Ray Curry, the IAD Director, has periodically reviewed with NAMS both the ISO's planned and completed audits. For efficiency going forward, rather than reconvening NAMS, I have asked that the review of the ISO's planned and completed audits be reviewed instead with the Budget & Finance Subcommittee, consistent with that Subcommittee's review of the ISO's annual SOC 1 audit results.

I will be asking you at the March 4 Participants Committee meeting whether, given the ISO's current audit plan and audits, there is any additional independent third-party audit that members would like the Participants Committee to consider requesting of the ISO this year. If so, please let me or NEPOOL Counsel know and we will schedule time at the April meeting to consider whether the Committee agrees to request an additional independent audit. I can be reached at dcavanaugh@ene.org; 413.896.6757 (cell), or you can reach out to Dave Doot at dtdoot@daypitney.com; 860.992.2455(cell).

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[1] With NAMS involvement, performance audits have been conducted in 2004, 2007, 2010/11, and 2015/16.

From: Curry, Raymond <rcurry@iso-ne.com>
Sent: Wednesday, January 13, 2021 1:50 PM
To: Doot, Dave <dtdoot@daypitney.com>
Cc: Jackman, Alan <ajackman@iso-ne.com>
Subject: ISO New England Internal Audit Department 2020/2021 Results

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Dave, hello – a summary of the ISO New England Internal Audit Department Audit Plan current status and projected results through 1/31/21 for the 1/1/20 through 3/31/21 Fifteen Month Audit Plan follows below. The attachment is a detailed listing of project status.

As with the draft audit plan previously sent, please let me know who the NAMS Chair and/or representative is and I will be glad to send this with an offer to meet/discuss.

Best Regards,
Ray

ISO New England Internal Audit Department 2020/2021 Results

Although conditions were particularly challenging due to the remote work posture, good progress was made on all aspects of the Audit Plan, including audits and reviews performed by the Internal Audit Department (IAD) at ISO, external audit and consulting firm engagements and assessments managed by IAD, and four Local Control Center EMS IT Support reviews and several third party vendor follow-ups performed remotely by IAD.

IAD actively managed 141 projects and special activities from the 2020/2021 Fifteen Month Audit Plan, including internal audit projects (124), external audits and reviews (10), and special projects (seven):

- Project load was slightly higher than the number of projects in recent years due to 14 projects that were unplanned but added to the plan (123 projects were managed in 2019, 124 in 2018, 122 in 2017, 116 in 2016, and 120 in 2015)
- Items delivered to date included 85 internal audit reports, review memos, follow-up reports, and other deliverables. Seven external audit reports, review memos, and auditor communications, and other deliverables (including 11 market system software certifications, seven Benefit Plans tax returns and two summary annual reports) were also completed. A total of 111 items have been delivered as a result of the 141 projects and special activities to date
- As planned for Q1 2021 and the carryover into Q2 2021, 29 projects are currently underway (with 14 deliverables expected in Q1/Q2 2021 and an additional 15 later in 2021). Additionally, five market system software certifications are expected in Q2 2021.

<u>2020 accomplishments included the following:</u>

- Continued to follow-up issues in the Market Monitoring Mitigation Audit, the FERC Filing Development, Coordination and Case Management Review, the Third Party Cyber Risk Management Review, the Potomac Economics Review, the Aspera Vendor Review, and several IT/Cyber Security related audits and reviews

- Continued to manage the ISO-NE SSAE 18 engagement and coordinate the management assertion controls validation and monitoring processes, resulting in a successful SOC 1 Type 2 Report with an unqualified opinion for the 16th consecutive year:
  - Added the DA Flagging control objective, the new NEXTT system and the Balancing Authority Checkout control activities to better align with current business processes
  - Coordinated the two KPMG remote test visits by reviewing the data request lists in detail, scheduling all the meetings between KPMG and the business process owners, timely communicating the engagement status, and helping to resolve any engagement issues
  - Managed the expanded positive automated testing in a test environment and in integration, and monitored the completeness and accuracy of reports testing
  - Completed testing for 38% of the control activities
  - In support of the Management Assertion Letter, monitored one occurrence of the control activities by the business process owner for 25% of the control activities
  - Maintained the master copy of the 2020 SOC 1 Type 2 Report, including all the updates/changes and numerous comprehensive detail reviews
- Successfully managed several external audit and review activities, including the three Benefit Plans Audits and seven related tax filings and two summary annual reports, 11 market system software certifications, and a Network Vulnerability Assessment
- To assist with NERC CIP compliance, performed the CIP-013-01 Supply Chain Risk Management Standard Readiness Review, completed the Bulk Electric System Tripwire/SigmaFlow Administration and Monitoring Review, and managed and coordinated the Network & Securities Technologies (N&ST) CIP Mock Audit, adjusting the scope to have minimal impact on IT resources during the COVID pandemic; also completed follow-ups of the CIP Oversight, Monitoring and Reporting Process Review, the CIP Vulnerability Patch and Baseline Management Audit, and the Pool Control Error Calculator Intrusion Prevention System Configuration Management Review
- Completed several follow-ups in the area of third party cyber risk management, including two follow-ups of the Third Party Cyber Risk Management Review, three follow-ups of the Potomac Economics Logical and Physical Security Administration Review, two follow-ups of the Aspera Security Administration and Change/Configuration Management Review, and one follow-up of the Power Auctions Change/Configuration Management Audit
- Directed and managed the co-sourcing of the Market Systems Web Application Server Security Administration Audit and the VMware Security Administration and Change/Configuration Management Audit conducted by PricewaterhouseCoopers
- Successfully negotiated with LCC compliance, IT and cyber security personnel to plan and conduct three LCC EMS IT Support Audits at Eversource (CONVEX, PSNH, NSTAR) and an additional one at VELCO remotely; also completed follow-ups of the National Grid and United Illuminating EMS/SCADA IT Support Audits
- Completed pre-implementation Software Development Life Cycle (SDLC) reviews for the Identity and Access Management, EMS EMP 3.2 Upgrade, Energy Storage Device, Offer Caps, CIMNET SFT, and Markets Database Oracle Upgrade project initiatives, as well as a post-implementation operations

review follow-up for the Price Responsive Demand project; completed a major review of the Software Development Life Cycle, Project Release and Code Management Processes

- Continued monitoring and reviewing developments regarding energy security improvements initiatives through completion of the Energy Market Opportunity Cost Calculation Review and Follow-up and the OP-21/Fuel Diversity Tool Review Follow-up
- Continued monitoring developments and initiatives in the areas of Edge Network Redesign, Employee/Guest Wireless Infrastructure, External Web Infrastructure, E-mail Infrastructure, Enterprise Phone System, Mobile Device Management and CIP Electronic Security Perimeter Improvements
- Based on requests from management, completed whitepaper and/or consulting in the areas of Cloud Services Security Administration and Change/Configuration Management, the ISO New England Password Change Policy, and the ACS Development, Testing and Migration Process
- Completed the Certificate Management and Deployment Review – Internal Users (N&ST) and several follow-ups of audits and reviews in IT/Cyber Security areas, including External Web Infrastructure, Certificate Management – External Users, Server, Network and Workstation Deployment, Retirement and Baseline Configuration Management, Cyber Security Group Security Information and Event Management (SIEM) Processes, and Data Governance/Data Management
- Completed several audits, reviews and follow-ups related to System Planning and System Operations in the areas of the Model On Demand Process, FERC Order 1000 Processes, Planning Authority Long Term/Short Term Planning Horizon Coordination, Sloped Demand Curve/Installed Capacity, the Dynamic Data Maintenance System, Operations Flagging, and ISO-NE Control Room Operations; also made progress on planning and field work for the Operational Load Forecasting Audit
- Completed several audits, reviews and follow-ups related to Market Operations in the areas of Generation Asset Registration, Blackstart Performance Auditing, Voltage Ampere Reactive Performance Auditing, Demand Resource Asset Registration, and Baseline Telemetry System Operations; also made progress on planning and field work for the Regulation Market Audit
- Performed annual and cyclic Finance and Human Resources audits and reviews in the areas of Corporate Performance Measures, Wire and ACH Transfers, Purchasing/Vendor Contracts, Independent Contractor/Consultant Administration, Executive/Board of Directors Expense Reporting and Compensation, Fraud, Waste and Abuse, and both API Bonus and LTI Calculation Processes; performed follow-ups of the Payroll, Employee Expense Reporting and Financial Assurance Audits

<u>Other 2020 activities included the following:</u>

- Provided over 300 hours of direct support for KPMG SOC 1 testing for 24 control objectives totaling 96 control activities and automated testing for the bid-to-bill application systems
- Managed the SOC 1 Controls Monitoring Forms process and compiled the 72 forms prepared by the business process owners for 57 control objectives and 229 control activities as part of the ongoing management assertion support
- Completed IAD testing of 11 of the 57 control objectives and 58 of the 229 control activities (25% of all control activities) as part of the ongoing management assertion support

- Effectively utilized several external resources, including Security Network Technologies, Network & Security Technologies (N&ST), PricewaterhouseCoopers, Meyers Brothers Kalicka, Verracy, and PA Consulting, to augment IAD resources
- Maintained schedule flexibility, which allowed IAD to handle numerous special requests by senior management and participants to perform additional review activities and/or change the timing of planned activities due to the COVID pandemic
- Tracked changes to existing control processes as a result of the COVID pandemic (ISO New England Password Change Policy, notary procedures for participant security administrators, etc.)
- Actively participated in the RSA Archer Project, including project team, governance and management meetings and making significant contributions to definition and identification of foundational data like business hierarchy, authoritative sources, and policies
- Completed the 2020/2021 IAD risk assessment process, effectively developing the 2020/2021 Fifteen Month Audit Plan that was approved by Audit and Finance Committee in March 2020 with no changes; nearly completed the 2021/2022 IAD risk assessment process, and have fully drafted the 2021/2022 Fifteen Month Audit Plan
- Continued to apply the ACL Data Mining/Data Analysis Tool to the semi-annual Fraud, Waste and Abuse Program

2020/2021 Fifteen Month Audit Plan Detailed Status As Of 1/31/21

Audit Area	Issuance/ Completion Date
External Audits/Reviews:	
SOC 1 - Project Management	11/30/20
SOC 1 - Direct Audit Support	10/2/20
SOC 1 - Ongoing Management Assertion Support	11/30/20
Benefit Plans Audits (3)	10/13/20
Financial Statements Audit	3/20/20
Market System Software Certifications	1/5/20 (1), 2/28/20 (5), 8/25/20 (1), 12/31/20 (2) 1/22/21 (1), 1/31/21(1)
2020 Network Vulnerability Assessment	10/21/20
2019 Network Vulnerability Assessment Follow-up	8/31/20
First Quarter & Carryover Activity:	
2019 Wire/ACH Transfers Audit	2/20/20
2019 API Bonus Review	4/10/20
2019 Performance Measures Final Review	1/30/20
Winter 2019 Fraud, Waste and Abuse Review	9/21/20
Summer 2019 Fraud, Waste and Abuse Review	9/21/20
Market Monitoring Procedures and Control Activities Review	
FERC Order 1000 Review	5/4/20
Generation Asset Registration Audit	4/7/20
Model On Demand Process Audit	6/15/20
Blackstart Performance Auditing Process Audit	6/23/20
Energy Market Opportunity Cost Calculation Review	1/8/20
Certificate Management and Deployment Review - Phase II (External Users)	2/14/20
SDLC, Project Release, and Code Management Review	7/16/20
Market Systems Web Application Server Security Administration and Change/Configuration Management Audit	11/21/20
FERC Filing Development, Coordination and Case Management Review Follow-up and Consulting - Phase I	2/18/20
CIP Oversight, Monitoring and Reporting Processes Review Follow-up – Phase II (compliance monitoring and internal controls)	2/19/20
2019 Employee Expense Reporting Audit	1/8/20
CIP Vulnerability Patch and Baseline Configuration Management Audit Follow-up – Phase I	1/15/20

Audit Area	Issuance/ Completion Date
Finance/Human Resources/Legal/Compliance/Market Monitoring:	
2020 Performance Measures Interim Review	12/31/20
2020 Performance Measures Final Review	1/31/21
2020 Purchasing/Vendor Contracts Audit	11/20/20
2020 Wire/ACH Transfers Audit	12/31/20
2020 LTI Calculation Review	8/20/20
2020 API Bonus Review	
401k Contribution Limit Review	7/17/20
Summer 2020 Fraud, Waste and Abuse Review	
Winter 2020 Fraud, Waste and Abuse Review	
2020 Independent Consultant/Contractor Administration Review	11/20/20
2020 Executive/Board of Directors Expense Reporting and Compensation Audit	10/15/20
System Planning Studies Refund Review	
2019 Payroll Audit Follow-up	4/28/20
2019 Employee Expense Reporting Audit Follow-up	8/5/20
Financial Assurance Policy Compliance Audit Follow-up - Phase II	2/13/20
FERC Filing Development, Coordination and Case Management Review Follow- up and Consulting - Phase II	
Market Monitoring Mitigation Audit Follow-up Phase III	10/30/20
Market Monitoring Procedures and Control Activities Follow-up	
Control Room Operations Controls Mapping (Compliance lead, IAD Support)	
NERC/Tariff Compliance (Compliance lead, IAD support)	
Operations/Market Development/Market Design:	
ISO-NE Control Room/Local Control Center Operations Audits/Follow-ups:	
NSTAR LCC Operations Audit	
ISO Control Room Operations Audit Follow-up	6/16/20
Dynamic Data Maintenance System Audit	10/21/20
Operational Load Forecasting Audit	
Voltage Ampere Reactive Performance Auditing Process Audit	1/22/31
Planning Authority Long/Short Planning Horizon Coordination Review	10/16/20
Regulation Market Audit	
Sloped Demand Curve/Installed Capacity Requirement Audit	1/15/21
Energy Market Opportunity Cost Calculation Review Follow-up	9/20/20
OP-21/Fuel Diversity Tool Review Follow-up	4/21/20
DR Asset Registration Audit Follow-up	5/30/20
Generation Asset Registration Audit Follow-up	
FERC Order 1000 Review Follow-up – cancelled, no findings	
BLTS Operations Audit Follow-up	10/8/20
Operations Flagging Audit Follow-up	2/24/20
Model On Demand Process Audit Follow-up	
Blackstart Performance Auditing Process Audit Follow-up – cancelled, no findings	

COLOR KEY:
Orange: Planning/Research
Yellow: Fieldwork/Detail Work in Process
Blue: Reporting/Nearing Completion
White: Not Started
Red: Cancelled

2020/2021 Fifteen Month Audit Plan Detailed Status As Of 1/31/21, Cont'd.

Audit Area	Issuance/ Completion Date
SDLC/Business Process Pre and Post Implementation Reviews:	
NERC Supply Chain Risk Management Standard Readiness Review (N&ST)	3/27/20
NERC Supply Chain Risk Management Standard Readiness Review (IAD)	6/2/20
JIRA Change Management System Post-implementation Review (KPMG)	
Identity and Access Management Project (Identityiq/SailPoint) Pre-implementation SDLC Review - Phase II	4/3/20
Identity and Access Management Project (Identityiq/SailPoint) Pre-implementation SDLC Review (KPMG)	
EMP 3.2 Upgrade Phase II Pre-implementation SDLC Review – Phase I	4/3/20
EMP 3.2 Upgrade Phase II SDLC Pre-implementation Review – Phase II	
EMP 3.2 Upgrade Phase II implementation Operations Review	
Energy Storage Device Project Phase II Pre-implementation SDLC Review	2/28/20
Energy Storage Device Project Phase II Post-implementation Operations Review	
Offer Caps Project Pre-implementation SDLC Review	2/28/20
CIMNET SFT Project Pre-implementation SDLC Review	4/3/20
Markets Database Refresh Oracle Upgrade (19C) Project Pre-implementation SDLC Review	2/28/20
Price Responsive Demand Project Post-implementation Operations Review Follow-up	4/28/20
Edge Network Redesign Project Monitoring/Planning	Complete
Employee/Guest Wireless Infrastructure Upgrade Monitoring/Planning	Complete
External Web Infrastructure Upgrade Project Monitoring/Planning	Complete
E-mail Infrastructure Upgrade Project Monitoring/Planning	Complete
Enterprise Phone System (Windstream) Project Monitoring/Planning	Complete

COLOR KEY:
Orange: Planning/Research
Yellow: Fieldwork/Detail Work in Process
Blue: Reporting/Nearing Completion
White: Not Started
Red: Cancelled

Audit Area	Issuance/ Completion Date
Information Services:	
IT Purchasing/Asset Management Audit	
Local Control Center/SCADA IT Support Audits/Follow-ups:	
CONVEX EMS IT Support Audit	1/4/21
PSNH EMS IT Support Audit	1/4/21
NSTAR EMS IT Support Audit	1/4/21
VELCO EMS IT Support Audit	12/31/20
Central Maine Power EMS IT Support Audit	
REMVEC LCC EMS IT Support Audit Follow-up	10/16/20
United Illuminating SCADA IT Support Audit Follow-up	1/15/21
Vendor Audits/Reviews/Follow-ups:	
GE/Alstom Security Administration and Change/Configuration Management Audit	
Potomac Economics Logical and Physical Security Administration Review Follow-up - Phase II	2/13/20
Potomac Economics Logical and Physical Security Administration Review Follow-up - Phase III	8/25/20
Potomac Economics Logical and Physical Security Administration Review Follow-up - Phase IV	Memo being drafted
Aspera Security Administration and Change/Configuration Management Review Follow-up - Phase II	5/19/20
Aspera Security Administration and Change/Configuration Management Review Follow-up - Phase III	1/22/21
2021 CIP NERC/NPCC Audit Readiness Review	11/19/20
VMware Security Administration and Change/Configuration Management Audit	11/19/20
Active Directory Security Administration and Change/Configuration Management Audit	
Mobile Device and Remote Access Security Administration and Change/Configuration Management Audit	
BES Tripwire/SigmaFlow Administration and Monitoring Review	Report being drafted
Cloud Services Security Administration and Change/Configuration Management Review	1/15/21

2020/2021 Fifteen Month Audit Plan Detailed Status As Of 1/31/21, Cont'd.

Audit Area	Issuance/ Completion Date
IT Follow-ups:	
External Web Infrastructure Security Administration and Change/Configuration Management Audit Follow-up - Phase III	7/2/20
MS Exchange Security Administration and Change/Configuration Management Audit Follow-up - Phase II	1/31/21
CIP Vulnerability, Patch and Baseline Configuration Management Audit – VIM/VPR/SigmaFlow Follow-up - Phase II	
PCEC IPS Configuration Management Review Follow-up - Phase II	5/7/20
Certificate Management and Deployment Review (External Users) Follow-up – Phase II	9/9/20
Certificate Management and Deployment Review (Internal Users) Follow-up - Phase I	
Server Deployment, Retirement and Baseline Configuration Management Processes Audit Follow-up - Phase III	9/10/20
Network and Workstation Deployment, Retirement and Baseline Configuration Management Proc. Audit Follow-up - Phase III	9/17/20
Cyber Security Group Monitoring/Security Information and Event Management (SIEM) Review Follow-up - Phase III	4/22/20
Third Party Cyber Risk Management Process Review - Phase III	12/11/20
SDLC, Project Release, and Code Management Review Follow-up	
Tripwire Administration and Support Review Follow-up	
Network Security Administration and Change/Configuration Management Audit Follow-up	
Third Party Remote Access Program, Protections and Security Measures Review Follow-up	
Market Systems Web Application Server Security Administration and Change/Configuration Management Audit Follow-up	
CISCO Identity Services Engine Security and Administration Review Follow-up	
Data Governance and Data Management Review Follow-up	4/30/20
Power Auctions Change/Configuration Management Audit - Follow-up - Phase III	10/2/20

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Audit Area	Issuance/ Completion Date
Special Projects:	-
SharePoint Maintenance	Ongoing
RSA Archer GRC Tool Development, Testing and Implementation	Ongoing
ACL Data Mining/Analysis Tool Development	Ongoing
IAD Internal Operations Training	
Issue Tracking	11/6/20
IAD Website	Ongoing
IAD Process/Procedure Update	Ongoing
ISO Audit Directors/Managers Group Information Sharing and Conference Preparation/Attendance	5/6/20, 9/22-9/23/20
NATF Supply Chain Management Working Group	Complete
NAMS Communications, Status Updates, Meetings	1/20/20, 1/29/20, 1/13/21 (2)
Internal/External Quality Assessment	
Additions to Schedule:	
Alight SOC 1 and SOC 2 Type 2 Reports Reviews (2)	4/24/20, 4/28/20
Alight SOC 1 and SOC 2 Mitigation Review	5/21/20
Businessolver SOC 1 and SOC 2 Type 2 Reports Review	5/13/20
401k Contribution Limit Review	7/17/20
457b Contribution Limit Review	7/17/20
Executive and Director Retention Agreement Review	10/15/20
Form 990 Disclosure Review	10/15/20
ACS Development, Testing and Migration Process Review	8/24/20
Password Change Policy Consulting	9/3/20
Physical Security Procedures CIP Compliance Review	10/27/20
Alight Open Enrollment Review	
Administration:	
General Administration	Ongoing
Director/Manager Project Allocation	Ongoing
Personnel Management	Ongoing
Budget & Forecasting	Ongoing
Audit & Finance Meetings	3/18/20, 8/20/20, 11/6/20
Performance & Risk Management Meetings	Ongoing
Annual Audit Planning	Ongoing
Training:	
Training	Ongoing
IIA Participation	Ongoing