NEPOOL
NEW ENGLAND POWER POOL

David T. Doot
Secretary

August 26, 2021

VIA ELECTRONIC MAIL

TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

RE: Supplemental Notice of September 2, 2021 NEPOOL Participants Committee Teleconference Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, initial notice is hereby given that the September meeting of the Participants Committee will be held **via teleconference on *Thursday*, September 2, 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.** To join WebEx, click this link and enter the event password **nepool**.

For your information, the September 2 meeting will be recorded. NEPOOL meetings, while not public, are open to all NEPOOL Participants, their authorized representatives and, except as otherwise limited for discussions in executive session, consumer advocates that are not members, federal and state officials and guests whose attendance has been cleared with the Committee Chair. All those 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 July 21, 2021 morning meeting and the August 5, 2021 meeting of the Participants Committee. The draft preliminary minutes of those meetings, marked to show changes from the draft circulated with the initial notice, are included with this supplemental notice and posted with the meeting materials.

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

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

4. To receive an ISO Chief Operating Officer report. The September COO report will be circulated and posted in advance of the meeting.

5. To receive a report on the following proposed budgets:

   a. 2022 ISO-NE Operating and Capital Budgets; and

   b. 2022 NESCOE Budget.

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

6. To consider and take action, as appropriate, on a request by Stored Solar J&WE, LLC for a waiver of the relevant provisions of the GIS Operating Rules and the GIS Agreement between NEPOOL and APX to allow for an adjustment to information on active Stored Solar Certificates. Background materials and draft resolutions 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
   - Transmission Committee
   - Budget & Finance Subcommittee
   - Membership Subcommittee
   - Others

9. Administrative matters.

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

PRELIMINARY

Pursuant to notice duly given, a special meeting of the NEPOOL Participants Committee was held via teleconference on Wednesday morning, July 21, 2021, beginning at 10:00 a.m., for the sole purpose of acting on the recommendation of the Joint Nominating Committee (JNC) for a four-person slate to be elected to the ISO Board in 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 special meeting.

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

CONFIDENTIAL VOTE ON SLATE OF CANDIDATES FOR ISO BOARD

Mr. David Cavanaugh referred to and summarized the public materials that had been circulated and posted in advance of the meeting and provided an overview of the confidential materials that had also been circulated. He thanked members for their input throughout the process followed by the JNC's unanimous recommendation of a slate for Participants Committee consideration. He reminded the Committee that the identities of the candidates on the proposed slate must remain confidential until the ISO Board takes its final vote on the slate on September 23. Acknowledging that some non-members had been invited to assist in presenting the slate, he identified the following people who had joined the meeting: Phil Shapiro, who had chaired the JNC; Matt Nelson, Chair of the Massachusetts Department of Public Utilities, who had been designated by the States to be their JNC representative that year; ISO General Counsel Maria Gulluni, who had co-authored the memorandum from counsel describing the legal processes that could be followed to act on a four-person slate; and Meredith Hatfield, the Executive Director of the New England Conference of Public Utility Commissioners (NECPUC). Mr. Cavanaugh then proposed that the Committee discuss the recommended slate entirely in executive session, and that proposal was accepted without objection.

EXECUTIVE SESSION

Mr. Cavanaugh recognized Phil Shapiro who referred to his confidential memo to the Committee and commented on the JNC process and the proposed slate. He thanked the JNC members, who had all been identified in his memo, for their participation in the process and identified each of the candidates on the slate and the expertise each would bring to the ~~board~~Board. He explained the reasons the JNC decided to propose a four-person slate given the exceptional quality of the candidates and the large turnover in ~~board~~Board membership over the next several years, both of which made the effort of choosing just three new candidates extraordinarily challenging for the JNC. He noted with appreciation the active support from NPC members for the JNC process through their candidate referrals, noting that, of the 23 potential candidates identified in the process, 19 were referred by members.

Mr. Cavanaugh then recognized Chairman Nelson, who thanked members for the opportunity to participate in the nomination process and expressed his appreciation for the collaborative way the JNC members worked through that process. Chairman Nelson noted his appreciation for the unique and unprecedented circumstances that resulted in a recommended four-person slate, and expressed his view that the slate would contribute to the strength of the Board going forward. He reported that slate had been reviewed confidentially with designated officials from each of the New England States and that he had not received any objections to the JNC proposal.

Mr. Cavanaugh then reminded members of the various presentations made to the Participants Committee throughout the selection process to improve the transparency of ~~the~~

~~nomination~~that process, and expressed his appreciation for the thoughtful and candid input from members throughout the process.

A number of members commended the ~~committee~~JNC and expressed their appreciation and support for the enhancements to the JNC process from the process followed in prior years. Some made clear that they supported the recommendation but only because of the highly unique circumstances that the region faced this year, which had been reviewed previously. On behalf of the ISO, Ms. Gulluni assured members that the ISO also saw the circumstances as highly unique, with the proposal to address the circumstances intentionally tailored to be narrow and limited in duration.

The four non-member guests were thanked for their participation and left the meeting. The Committee then proceeded to discuss the recommended slate and the process for acting on that recommendation. Following that discussion, a motion to endorse the slate as presented was duly made and seconded. The meeting was paused to permit the vote on that motion to be accomplished by secret written ballot, per prior agreement of the Participants Committee. The Secretary confirmed that the motion had been approved by more than the 70% Vote required for NEPOOL endorsement.

The following resolutions were then duly made, voted together without objection, and ~~were~~ unanimously approved:

> RESOLVED, that the Participants Committee approves the temporary waivers of relevant parts of the Participants Agreement, as set forth in the Waiver Agreement circulated to this Committee with the July 14 Supplemental Notice and posted with the materials for this meeting, in order to allow the four-person slate of candidates recommended by the JNC as circulated confidentially and presented to the Participants Committee in executive session at this meeting to be seated as board members if endorsed by the Participants Committee and elected by the ISO Board, subject to confirmation of such approval through the balloting process set forth in Section 17.2.3 of the Participant Agreement for amendments to the Agreement.

> RESOLVED, that the Balloting Agent (as defined in the Second Restated NEPOOL Agreement) is authorized and directed to circulate ballots for written approval of the Waiver Agreement, to each Participant for execution by its voting member or alternate on this Committee or such Participant's duly authorized officer.
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> RESOLVED, that the Participants Committee Chair is authorized to execute the Waiver Agreement on behalf of NEPOOL and NEPOOL Counsel is directed and authorized to make any filing(s) as it deems reasonably necessary to implement the Waiver Agreement if approved.

There being no further business, the morning meeting adjourned at 11:20 a.m., with Mr. Cavanaugh reminding ~~the~~ members of the Future Pathways working session that would convene later that day at 1:00 p.m.

Respectfully submitted,

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David Doot, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN THE JULY 21, 2021 AM TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Advanced Energy Economy	Fuels Industry Part.	Caitlin Marquis		
AR Large Renewable Generation (RG) Group Member	AR-RG	Alex Worsley		
AR Small Load Response (LR) Group Member	AR-LR	Brad Swalwell		
AR Small Renewable Generation Group Member	AR-RG	Erik Abend		
Ashburnham Municipal Light Plant	Publicly Owned		Brian Thomson	
AVANGRID: CMP/UI	Transmission	Alan Trotta		
Belmont Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Block Island Utility District	Publicly Owned	Dave Cavanaugh		
Borrego Solar Systems, Inc.	AR-DG	Liz Delaney		
Boylston Municipal Light Department	Publicly Owned		Brian Thomson	
BP Energy Company	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned			Dave Cavanaugh
Calpine Energy Services, LP	Supplier	Brett Kruse		Bill Fowler
Castleton Commodities Merchant Trading	Supplier			Bob Stein
Chester Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned		Brian Thomson	
Clearway Power Marketing LLC	Supplier			Pete Fuller
Concord Municipal Light Plant	Publicly Owned		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned	Brian Forshaw		
Conservation Law Foundation (CLF)	End User	Phelps Turner		
CPV Towantic, LLC	Generation	Joel Gordon		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned		Dave Cavanaugh	
DC Energy, LLC	Supplier	Bruce Bleiweis		
DTE Energy Trading, Inc.	Supplier			José Rotger
Dynegy Marketing and Trade, LLC	Supplier	Andy Weinstein		Bill Fowler
Emera Energy Services	Supplier			Bill Fowler
Environmental Defense Fund	End User	Jolette Westbrook		
Eversource Energy	Transmission	James Daly	Dave Burnham	
Exelon Generation Company	Supplier		Bill Fowler	
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc.	Supplier	José Rotger		
Generation Group Member	Generation	Dennis Duffy		
Georgetown Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Great River Hydro	AR-RG			Bill Fowler
Groton Electric Light Department	Publicly Owned		Brian Thomson	
Groveland Electric Light Department	Publicly Owned		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc.	Supplier	Louis Guibault	Bob Stein	
High Liner Foods (USA) Incorporated	End User		William P. Short III	
Hingham Municipal Lighting Plant	Publicly Owned		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned		Brian Thomson	
Holyoke Gas & Electric Department	Publicly Owned		Brian Thomson	
Hull Municipal Lighting Plant	Publicly Owned		Brian Thomson	
Industrial Energy Consumer Group (IECG)	End User	Alan Topalian		
Ipswich Municipal Light Department	Publicly Owned		Brian Thomson	
Jericho Power LLC (Jericho)	AR-RG	Mark Spencer	Nancy Chafetz	
Littleton (MA) Electric Light and Water Department	Publicly Owned		Dave Cavanaugh	
Long Island Power Authority (LIPA)	Supplier		Bill Killgoar	
Maine Power LLC	Supplier	Jeff Jones		

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PARTICIPATING IN THE JULY 21, 2021 AM TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Maine Public Advocate’s Office	End User	Andrew Landry		Erin Camp
Maine Skiing, Inc.	End User	Alan Topalian		
Mansfield Municipal Electric Department	Publicly Owned		Brian Thomson	
Maple Energy LLC	AR-LR			Doug Hurley
Marblehead Municipal Light Department	Publicly Owned		Brian Thomson	
Mass. Attorney General’s Office (MA AG)	End User	Christina Belew	Ben Griffiths	
Mass. Bay Transportation Authority	Publicly Owned		Dave Cavanaugh	
Mass. Municipal Wholesale Electric Company	Publicly Owned	Brian Thomson		
Mercuria Energy America, Inc.	Supplier			José Rotger
Merrimac Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Michael Kuser	End User		Jason York	
Middleborough Gas & Electric Department	Publicly Owned		Dave Cavanaugh	
Middleton Municipal Electric Department	Publicly Owned		Dave Cavanaugh	
National Grid	Transmission	Tim Brennan	Tim Martin	
Natural Resources Defense Council	End User	Bruce Ho		
Nautilus Power, LLC	Generation		Bill Fowler	
New England Power Generators Association (NEPGA)	Fuels Industry Part	Bruce Anderson	Dan Dolan	
New Hampshire Electric Cooperative	Publicly Owned			Brian Forshaw
NextEra Energy Resources, LLC	Generation	Michelle Gardner		
North Attleborough Electric Department	Publicly Owned		Dave Cavanaugh	
Norwood Municipal Light Department	Publicly Owned		Dave Cavanaugh	
NRG Power Marketing LLC	Generation		Pete Fuller	
Pascoag Utility District	Publicly Owned		Dave Cavanaugh	
Paxton Municipal Light Department	Publicly Owned		Brian Thomson	
Peabody Municipal Light Department	Publicly Owned		Brian Thomson	
Princeton Municipal Light Department	Publicly Owned		Brian Thomson	
PSEG Energy Resources & Trade LLC	Supplier	Eric Stallings		
Reading Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Rowley Municipal Lighting Plant	Publicly Owned		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned		Brian Thomson	
Shrewsbury Electric & Cable Operations	Publicly Owned		Brian Thomson	
South Hadley Electric Light Department	Publicly Owned		Brian Thomson	
Sterling Municipal Electric Light Department	Publicly Owned		Brian Thomson	
Stowe Electric Department	Publicly Owned		Dave Cavanaugh	
Sunrun Inc.	AR-DG			Pete Fuller
Taunton Municipal Lighting Plant	Publicly Owned		Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned		Brian Thomson	
The Energy Consortium	End User	Bob Espindola	Mary Smith	
Vermont Electric Power Company	Transmission	Frank Ettori		
Vermont Energy Investment Corp (VEIC)	AR-LR		Doug Hurley	
Vermont Public Power Supply Authority	Publicly Owned			Brian Forshaw
Versant Power	Transmission	Lisa Martin		
Village of Hyde Park (VT) Electric Department	Publicly Owned		Dave Cavanaugh	
Vitol Inc.	Supplier	Joe Wadsworth		
Wakefield Municipal Gas & Light Department	Publicly Owned		Brian Thomson	
Wallingford DPU Electric Division	Publicly Owned		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned		Dave Cavanaugh	
West Boylston Municipal Lighting Plant	Publicly Owned		Brian Thomson	
Westfield Gas & Electric Department	Publicly Owned		Dave Cavanaugh	
Wheelabrator North Andover, Inc.	AR-RG		Bill Fowler	

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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, August 5, 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.

APPROVAL OF JUNE 24, 2021 MEETING MINUTES

Mr. Cavanaugh referred the Committee to the preliminary minutes of the June 24, 2021 meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of that meeting were unanimously approved as circulated, 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 an abstention on behalf of Mr. Kuser's alternate recorded.

ISO CEO REPORT

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

24, 2021 Participants Committee meeting, which had been circulated and posted in advance of the meeting. There were no questions or comments on the summaries.

ISO COO REPORT

July Report (June data) Update

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), began by briefly highlighting a few items from his report circulated in early July, which covered the full month of June. He reported that load forecasting was impacted by two heatwaves in June. The first heatwave, which ran from June 5 to June 9, had a 15 to 17 degrees Fahrenheit (°F) departure from mean temperatures. During this time, the load forecasts were reasonably accurate except on June 9, when the peak temperature was under-forecasted by approximately 5°F. The second heatwave, which resulted in even higher temperatures, took place from June 28 to June 30. During this time temperatures again ran 15 to 17°F higher than the mean. The weather forecasts during this time were more accurate, resulting in a more accurate load forecasts. Dr. Chadalavada then clarified the peak load numbers for June reflected in the July report. He explained that peak load was initially reported as 25,159 MW, but was subsequently increased to 25,726 MWs to reflect data from revenue quality meters settlement-only generation. Reflecting on reported uplift, he noted that higher uplift occurred when insufficient generation in the east cleared during time of high loads and/or gas prices, resulting in out-of-merit dispatch and costs. Finally, he reported that the aggregate show of interest for FCA16 totaled 16,200 MWs (5,800 MW of supply, 9,900 MW of imports, and 530 MW of demand resources), just 1,000 MW shy of the show of interest for FCA15.

August Report (July data)

Referring the Committee to his August report, which had been circulated and posted in advance of the meeting, Dr. Chadalavada noted that the data in the report was through July 28, 2021, unless otherwise noted. The report highlighted the following: (i) Energy Market value for July 2021 was $427 million, down $51 million from the updated June 2021 value of $478 million and up $100 million from July 2020; (ii) July 2021 average natural gas prices were 14% higher than June average prices; (iii) average Real-Time Hub Locational Marginal Prices (LMPs) for July ($36.04/MWh) were 0.6% higher than June averages; (iv) average July 2021 natural gas prices and Real-Time Hub LMPs over the period were up 99% and 60%, respectively, from July 2020 average prices; (v) average Day-Ahead cleared physical energy during peak hours as percent of forecasted load was 100.6% during July (up from 99.1% in June), with the minimum value for the month (96.2%) on July 4; and (vi) Daily Net Commitment Period Compensation (NCPC) payments for July totaled $2.7 million, which was down $1.2 million from June 2021 and up $0.9 million from July 2020. July NCPC payments, which were 0.6% of total Energy Market value, were comprised of: (a) $2.1 million in first contingency payments (down $0.6 million from June); (b) $331,000 in second contingency payments (down $850,000 from June), and (c) $276,000 in distribution payments (up $245K from June).

Dr. Chadalavada noted that Future Grid Reliability Study results were presented at the July Planning Advisory Committee (PAC) meeting, and the remaining results ~~are~~were expected to be presented in September.

Responding to questions about upcoming transmission outages, Dr. Chadalavada noted potential outages later in the year on lines 312/393 and 354, both of which were expected to impact the New England/New York interface limits and result in uplift charges. The requests for both outages were being analyzed and ~~he~~Dr. Chadalavada committed to provide an update at the September meeting.

LITIGATION REPORT

Mr. Doot referred the Committee to the August 3 Litigation Report that had been circulated and posted in advance of the meeting. He highlighted the following:

(i) three FERC administrative and rulemaking proceedings addressing, respectively, resource adequacy, hybrid resources and transmission interconnection and planning. He noted that the advanced notice of proposed rulemaking (ANOPR) on transmission interconnection and planning (Transmission ANOPR) had generated a fair amount of questions and would be discussed at the next Transmission Committee meeting; and

(ii) activity in the proceeding initiated by the filing concerning treatment in Regional Network Load of behind-the-meter generation that had been submitted jointly on July 1 by the ISO and the Participating Transmission Owners Administrative Committee.

COMMITTEE REPORTS

Markets Committee (MC). Mr. William Fowler, the MC Vice-Chair, reported that a three-day meeting would be held August 10-12, with a potential fourth day on August 31. Discussion would focus on the region's response to Order 2222 and Minimum Offer Price Rule (MOPR) reform issues.

Reliability Committee (RC). Mr. Robert Stein, the RC Chair, reported that the scheduled August 17 RC meeting would include discussion on FCA16 ~~retirement and de-list bids~~Retirement and De-List Bids and certain Order 2222 issues.

Transmission Committee (TC). Mr. José Rotger, the TC Vice-Chair, reported that the scheduled August 24 TC meeting would include: (i) continued discussion on a stakeholder proposal to eliminate from Schedule 11 of the Tariff operating and maintenance (O&M) charges for network upgrades associated with generation interconnections; (ii) information on ISO-proposed changes to Attachment K, which would include changes to the regional system planning process and changes relative to lessons learned from the Order 1000 transmission request for proposals (RFP) process, and (iii) an overview by NEPOOL counsel of the Transmission ANOPR and consideration of any NEPOOL response thereto.

Budget & Finance Subcommittee. Mr. Thomas Kaslow, the Subcommittee Chair, announced that the Subcommittee would hold two meetings in August, one on August 9 to review the preliminary 2022 ISO and NESCOE budgets, and one on August 26 to take up ongoing issues before the Subcommittee, including nodal clearing of FTRs.

Membership Subcommittee. Ms. Sarah Bresolin, the Subcommittee Chair, announced that the next meeting of the Subcommittee, which was scheduled for August 16, would include consideration and discussion of potential changes to the characterization of the Fuels Industry Participant membership category (which had expanded to include a few trade association members). Ms. Bresolin reminded Participants that Subcommittee materials, including an expected straw proposal with respect to the Fuels Industry Participant arrangements, would be available on the Subcommittee's NEPOOL website page. She welcomed Participants with any questions or concerns about the straw proposal or other Subcommittee ~~matter~~matters to forward those to her or to NEPOOL counsel.

ADMINISTRATIVE MATTERS

Mr. Cavanaugh noted that the Pathways Study meeting scheduled for August 23 had been cancelled, with a next meeting tentatively scheduled for September 23 (date and time to be subsequently confirmed). In addition, the October NPC meeting was tentatively being planned as an in-person meeting. He said that all Participants would receive a questionnaire to support meeting planning and logistics and to receive feedback for restoring in-person NEPOOL meetings.

Finally, he referred to the notice from NEPOOL counsel that balloting of the Waiver Agreement, which allows for the temporary Participants Agreement waivers required to seat the four-person slate of candidates for election to the ISO Board of Directors endorsed by the Participants Committee at its July 21 meeting, was successfully completed and the Agreement was unanimously approved. He said that notice of that Agreement would be filed with the FERC. A final vote by the ISO Board of Directors to approve the Waiver Agreement and elect the slate was expected to be taken at the Board's meeting in September.

NESCOE ADVANCING THE VISION REPORT

After a brief recess, Mr. Cavanaugh introduced Ms. Heather Hunt, NESCOE Executive Director, along with Mr. Phil Bartlett, Chair, Maine Public Utilities Commission; Mr. Matt Nelson, Chair, Massachusetts (MA) Department of Public Utilities; Ms. June Tierney, Commissioner, Vermont Department of Public Service (VT DPS); and Mr. Patrick Woodcock, MA Commissioner and Undersecretary of Energy.

Ms. Hunt began by referring to the "*Report to the Governors: Advancing the Vision*" (Report), which had been circulated and posted in advance of the meeting. The Report followed the October 2020 issuance of both the New England States' Vision Statement and the Statement on Electricity System Reform issued by five of the six governors (the New Hampshire governor was not a signatory to the latter Statement, reflecting primarily differences in clean energy mandates between New Hampshire and the other New England states). She summarized the process undertaken prior to the Report, including a number of issue-specific technical sessions that were held in early 2021, expressing thanks to all those who participated in those sessions.

Ms. Hunt first highlighted the Report's market design recommendations, which included moving a forward clean energy market (FCEM)-style construct to the next level of detail to help the States further inform their thinking, as well as continuing work on the elimination of the MOPR and other market adjustments such as- energy and ancillary services. The Commissioners in follow up reflected on the importance of taking a holistic approach to ensuring clean energy resources can be integrated into the clean energy transition effectively. Also stressed was the importance of market-based goals and other market elements, including energy and ancillary services. Members noted the FERC's initiative to define a grid services framework through Order 2222 and otherwise.

Ms. Hunt next highlighted the recommendation focused on conducting transmission analysis over a long-term horizon consistent with the Vision Statement and in furtherance of state policies or mandates. In Fall 2020, based on this recommendation, the ISO agreed to conduct a 2050 transmission study, which was expected to be brought to stakeholders for comment in the near term. Further, Ms. Hunt- highlighted the importance of an associated timely reform to the ISO's transmission planning tariff to make proactive, long-term scenario-based analysis of state mandates and policies a routine planning practice. She noted that the FERC's recently-released Transmission ANOPR incorporated many of the objectives included in the

~~vision statement~~Vision Statement. She also highlighted the FERC's establishment of the joint federal-state task force on electric transmission which, as noted in the Litigation Report, included the nominations of New England Commissioners Riley Allen (VT PUC) and ~~Chair~~Chairman Nelson, with work likely to begin in the late Fall. Commissioners noted the challenges, but nevertheless the need, to produce analysis of transmission infrastructure to meet long-term goals and mandates on a low-cost basis.

Turning to the Report's third area of recommendations, highlighting ISO governance and the assessment of governance practices used by other regional transmission operators, Ms. Hunt noted that the Report offered a list of recommendations that would enhance the ISO's transparency and accountability. Commissioners augmented that summary, noting the importance of the ISO's governance changing in order to be more responsive to rapidly evolving state mandates and energy policy changes. The ~~states~~States sought more collaborative partnering with the ISO to achieve common goals.

Turning to equity and environmental justice, Ms. Hunt shared the recommendation to create an Ad Hoc State Work Group on Equity and Environmental Justice in Energy Infrastructure, comprised of New England state officials with policy, permitting, siting, and regulatory authorities and regional partners, and included ISO and NEPOOL Sector representatives. The Commissioners recognized that equity and environmental justice was a new and evolving initiative that required a fundamental shift in how challenges were defined and addressed and that needed to be tackled together with the ISO and stakeholders.

Members were invited then to ask questions and comment on the Report, beginning with the theme of equity and environmental justice. That discussion highlighted the importance of including such considerations in all planning discussions and finding new ways to provide transparency for such discussions and to facilitate input on environmental and social equity issues from those who are historically under-represented. The Commissioners said that the region had an imperative to ensure that environmental and equity issues become part and parcel of engineering and economic thinking going forward. Continuing, the Commissioners expressed the view that the process for considering such issues needed to ensure communities would be engaged and to provide clear understanding of when, where and how to provide meaningful input. There was acknowledgement that the changes to the current legal frameworks for considering such issues that most directly impact environmental justice and equity were under development at both the state and federal levels, and those frameworks also need to be incorporated into regional processes.

On the topic of governance, Ms. Hunt noted the ISO's report that the governance recommendations had been referred to the ISO's Nominations and Governance Committee and were reportedly to be taken up by that Committee and the Board in August. The States expected the Board would issue a response thereafter but did not know whether the ISO Board would need additional time beyond its August meeting. Thus, the next steps by the States on the governance initiative would follow the ISO Board response.

As to the discussion on the other topics, the Committee was referred to ongoing discussions in the Technical Committees of the States' recommendations.

IMM 2020 ANNUAL MARKETS REPORT

Dr. Jeffrey McDonald, the ISO's Internal Market Monitor (IMM) and Vice President of Market Monitoring, was introduced to summarize the IMM's 2020 Annual Markets Report. Dr. McDonald began by providing an overview of the New England markets' performance in light of the record low natural gas prices, the impact of the COVID-19 pandemic on electricity demand, and the region's mild 2020 winter. As referenced in his presentation, Dr. McDonald reported that New England saw record low energy prices, as well as wholesale costs that decreased by more than $1 billion from 2019. He also reported that the system was relatively incident free in 2020, experiencing no shortage events and a few instances of operator intervention.

Dr. McDonald referred to a chart in his presentation that showed prices during the past year were insufficient to support new investment. The IMM's analysis, which was updated from prior reports to include Regional Greenhouse Gas Initiative (RGGI) prices, showed that the wholesale markets were not providing enough revenues to make it profitable enough to build the hypothetical CONE (Cost of New Entry) reference unit. Dr. McDonald clarified, in response to a question, that such results did not show that markets were not working. Rather, it reflected that, during the current times of surplus, new investment was not encouraged by the markets. He added that there could be a problem if this situation persisted over the long-term when supply and demand were more balanced.

Dr. McDonald presented on how CO_2 costs for certain resources increased their production costs. Specifically, RGGI increased costs by $2.88/MWh and the Massachusetts Global Warming Solutions Act produced a $3.08/MWh increase. In response to stakeholders' requests, Dr. McDonald committed to report on how the Massachusetts program impacted dispatch order. He also noted the IMM's findings about the impact on demand due to the increase of energy efficiency and behind-the-meter photovoltaic solar resources, observing that energy efficiency had the most pronounced load reducing impact.

Dr. McDonald concluded his presentation by offering the IMM's analysis of the competitiveness of the markets, which included a summary of mitigation measures taken in

2020. He highlighted the low occurrences of market power, as well as the low mitigation instances resulting from the potential for market power. Dr. McDonald also noted that, although the system as a whole was competitive in FCA15, there were a large number of pivotal suppliers (with potential market power), as determined by the pivotal supplier test, in the Southeast New England zone. In response to this observation, Dr. McDonald engaged stakeholders in a dialogue concerning the pivotal supplier test as it is used in the descending clock auction, as well as a brief conversation on changing the auction to a sealed-bid auction.

Upon completing his presentation, the Committee requested that Dr. McDonald provide his opinions on the removal of the MOPR from the ISO Tariff. Dr. McDonald and the Committee, with input from the Markets Committee officers and numerous stakeholders scheduled to present at the August 10–12, 2021 Markets Committee meeting, agreed to find time for that discussion at ~~the upcoming Markets Committee~~that August meeting.

Briefly summarizing his views at the request of a member, Dr. McDonald noted that the proposal from Potomac Economics had interesting features that, when combined with Effective Load Carrying Capability (ELCC), could maintain price formation even though public funds would be allowed to compete with private investment. Thus, in retaining price formation, the Potomac Economics proposal and ELCC could help coordinate entry and exit of resources, which, according to Dr. McDonald, was a key desired function of capacity markets. Dr. McDonald, however, was clear that he needed more time to review the Potomac Economics proposal before offering any opinion as to whether he supports it. He stated that he would be more fully prepared to discuss that proposal at the upcoming Markets Committee meeting.

There being no other business, the meeting adjourned at 2:20 p.m.

Respectfully submitted,

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David Doot, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN THE AUG 5, 2021 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Advanced Energy Economy	Fuels Industry Participant	Caitlin Marquis		
American Petroleum Institute	Fuels Industry Participant	Paul Powers		
Ampersand Energy Partners LLC	Supplier			Julia Frayer
AR Large Renewable Generation (RG) Group Member	AR-RG	Alex Worsley		
AR Small Load Response (LR) Group Member	AR-LR			Doug Hurley
Ashburnham Municipal Light Plant	Publicly Owned Entity		Brian Thomson	
Associated Industries of Massachusetts (AIM)	End User			Mary Smith
AVANGRID: CMP/UI	Transmission		Alan Trotta	
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
Borrego Solar Systems Inc.	AR-DG	Liz Delaney		
Boylston Municipal Light Department	Publicly Owned Entity		Brian Thomson	
BP Energy Company	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity			Dave Cavanaugh
Brooks, Dick	End User	Dick Brooks		
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		
Conservation Law Foundation (CLF)	End User	Phelps Turner		
CPV Towantic, LLC (CPV)	Generation	Joel Gordon		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Dominion Energy Generation Marketing	Generation	Mike Purdie	Weezie Nuara	
DTE Energy Trading, Inc.	Supplier			José Rotger
Dynegy Marketing and Trade, LLC	Supplier			Bill Fowler
Emera Energy Services	Supplier			Bill Fowler
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Environmental Defense Fund	End User	Jolette Westbrook		
Eversource Energy	Transmission	James Daly	Dave Burnham	Vandan Divatia
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	
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Great River Hydro	AR-RG			Bill Fowler
Groton Electric Light Department	Publicly Owned Entity		Brian Thomson	
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQUS)	Supplier		Bob Stein	
High Liner Foods (USA) Incorporated	End User		William P. Short III	
Hingham Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Holyoke Gas & Electric Department	Publicly Owned Entity		Brian Thomson	
Hull Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
Industrial Energy Consumer Group	End User	Alan Topalian		
Ipswich Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Jericho Power LLC (Jericho)	AR-RG	Mark Spencer	Nancy Chafetz	
Littleton (MA) Electric Light and Water Department	Publicly Owned Entity		Dave Cavanaugh	

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN THE AUG 5, 2021 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Littleton (NH) Water & Light Department	Publicly Owned Entity		Craig Kieny	
Long Island Power Authority (LIPA)	Supplier		Bill Killgoar	
Maine Power LLC	Supplier	Jeff Jones		
Maine Public Advocate's Office	End User	Drew Landry		
Maine Skiing, Inc.	End User	Alan Topalian		
Mansfield Municipal Electric Department	Publicly Owned Entity		Brian Thomson	
Maple Energy LLC	AR-LR		Luke Fishback	Doug Hurley
Marblehead Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Mass. Attorney General's Office (MA AG)	End User	Tina Belew	Ben Griffiths	
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity	Brian Thomson		
Mercuria Energy America, LLC	Supplier			José Rotger
Merrimac Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Michael Kuser	End User		Jason York	
Middleborough Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Middleton Municipal Electric Department	Publicly Owned Entity		Dave Cavanaugh	
National Grid	Transmission	Tim Brennan	Tim Martin	
Nautilus Power, LLC	Generation	Dan Pierpont	Bill Fowler	
New Hampshire Electric Cooperative	Publicly Owned Entity	Steve Kaminski		Brian. Forshaw; Dave Cavanaugh; Brian Thomson
New England Power Generators Association (NEPGA)	Fuels Industry Participant	Bruce Anderson	Dan Dolan	
NextEra Energy Resources, LLC	Generation	Michelle Gardner		Gabe Hollis
North Attleborough Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Norwood Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Pascoag Utility District	Publicly Owned Entity		Dave Cavanaugh	
Paxton Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Peabody Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Princeton Municipal Light Department	Publicly Owned Entity		Brian Thomson	
PSEG Energy Resources & Trade LLC (PSEG)	Supplier		Eric Stallings	
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity		Brian Thomson	
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Brian Thomson	
Small RG Group Member	AR-RG	Erik Abend		
South Hadley Electric Light Department	Publicly Owned Entity		Brian Thomson	
Sterling Municipal Electric Light Department	Publicly Owned Entity		Brian Thomson	
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Taunton Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
The Energy Consortium	End User	Bob Espindola	Mary Smith	
Vermont Electric Cooperative	Publicly Owned Entity	Craig Kieny		
Vermont Electric Power Company (VELCO)	Transmission	Frank Ettori		
Vermont Energy Investment Corp (VEIC)	AR-LR		Doug Hurley	
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw
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 August 17, 2021 meeting, dated August 17, 2021.[1]

1. **Changes to OP-24 (Adoption of RAS Terminology; Reference Updates; NRA language Removal; Changes to Section VI (Relay Characteristics Provided to the ISO))**

   Support revisions to ISO New England Operating Procedure (OP) No. 24 (Protection Outages, Settings and Coordination), which include revisions to adopt Remedial Action Schemes (RAS) terminology, to update References, to remove Non Reclosing Assurance (NRA) language, and to the section on "Relay Characteristics Provided to the ISO", as recommended by the RC at its August 17, 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 Appendix B to OP-14 (OP-14B) (Periodic Review Changes)**

   Support revisions to OP-14B (Generator and Asset Related Demand Reactive Data Explanation of Terms and Instructions for Data Preparation for ISO Form NX-12D), including clarifications to data values determinations, updates to voltage schedule and control data values, and updates to grammar and current terminology usage, as recommended by the RC at its August 17, 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.

Summary of ISO New England Board and Committee Meetings

September 2, 2021 Participants Committee Meeting

Since the last update, the Nominating and Governance Committee met on August 5, the Audit and Finance Committee met on August 18, and the Markets Committee on August 19. The Board of Directors met on July 16 and August 19. All of the meetings were held by videoconference.

The Nominating and Governance Committee reviewed board leadership and committee membership assignments, and assignment of Board members to state liaison roles. Those assignments will be presented to the Board for approval at the Board's annual meeting, held in September. In addition, the Committee discussed the orientation program for new directors. The Committee also considered the governance recommendations contained in the states' recent report to the Governors regarding the energy vision. The Committee discussed and agreed to recommend that the Board adopt a stakeholder engagement policy requiring that directors share information about material conversations with states and stakeholders to ensure that all are coordinated and informed of critical issues. The Committee then considered the format of Board and Committee meetings for 2021-22.

The Audit and Finance Committee received an update regarding the development of the 2022 operating and capital budgets, including a review of the capital structure, and an update on budget discussions with stakeholders. The Committee also conducted its annual review of the Company's insurance program. The Committee then received an update on the 2021 budget, and approved the use of contingency funds for projects related to Minimum Offer Price Rule Elimination, Future Grid studies including the 2050 transmission study, resource capacity accreditation work, and extreme weather and contingency modeling. The Committee approved the second quarter unaudited financial statements after management confirmed that all relevant disclosures from managers were included in the financial statements. The Committee received an update on internal audit activities, as well as highlights of recent external audits. Lastly, in executive session, the Committee reviewed the results of its self-evaluation.

The Markets Committee received reports from both market monitors on market operations in Spring 2021, and was provided with an overview of management's responses to the Market Monitors' annual reports. The Committee held a general discussion of the market design recommendations included in the states' report to the New England governors, and reviewed compliance with its committee charter. The Committee proposed enhancing its charter to include a reference to the Committee's oversight of the Company's efforts to integrate state energy policy goals. During executive session, the Committee reviewed the results of its self-evaluation.

The Board of Directors met in July to review a summary of the states' report to the New England governors regarding the markets, transmission, and governance issues outlined in the states' energy vision. At the Board's August meeting, the Board reviewed protocols for the anticipated return of the Company workforce to the office. The Board also received reports from the standing committees and, during the Nominating and Governance Committee report, approved the stakeholder engagement policy. The Board also discussed the governance recommendations in the states' report to the New England Governors. The Board reflected on markets issues regarding the elimination of the Minimum Offer Price Rule, and received an overview of the resource capacity accreditation project. In each case, the Board discussed the history of the initiative and related activities in other regions, as well as stakeholder input.

NEPOOL Participants Committee Report

September 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: July 2021 Energy Market value totaled $463M
  - August Energy market value over the period was $534M, up $71M from July 2021 and up $229M from August 2020
    - August natural gas prices over the period were 22% higher than July 2021 average values
    - Average RT Hub Locational Marginal Prices ($48.83/MWh) over the period were 37% higher than July 2021 averages
      - DA Hub: $48.30/MWh
    - Average August 2021 natural gas prices and RT Hub LMPs over the period were up 161% and up 105%, respectively, from August 2020 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 100.4% during August, down from 100.6% during July*
    - The minimum value for the month was 95.9% on Friday, August 6th

All data through August 25th

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

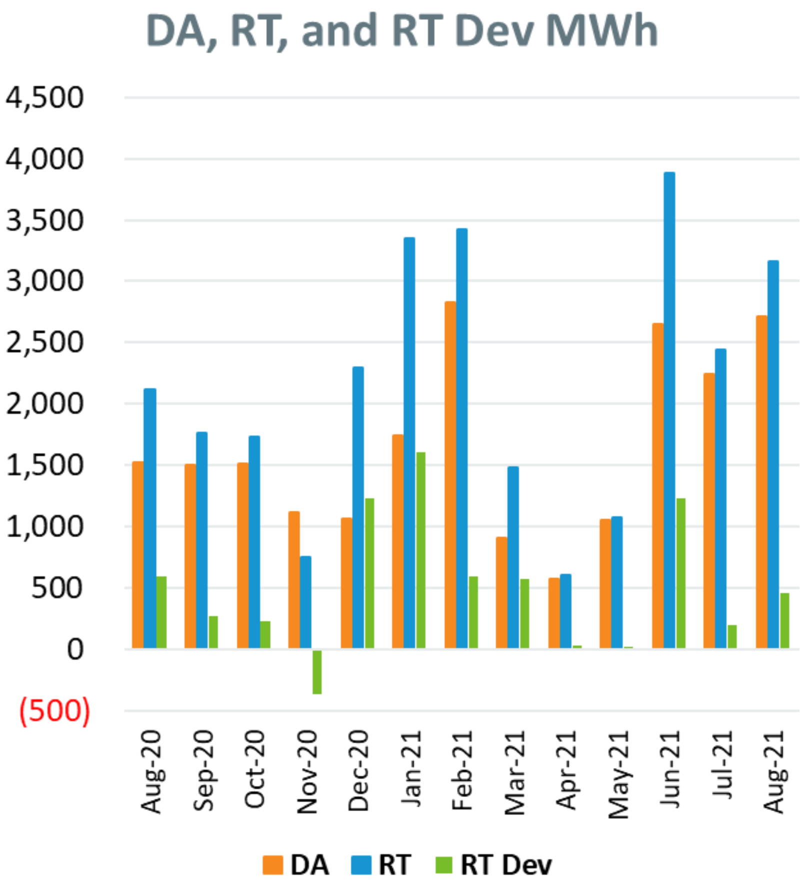
Underlying natural gas data furnished by: ice Global markets in clear view

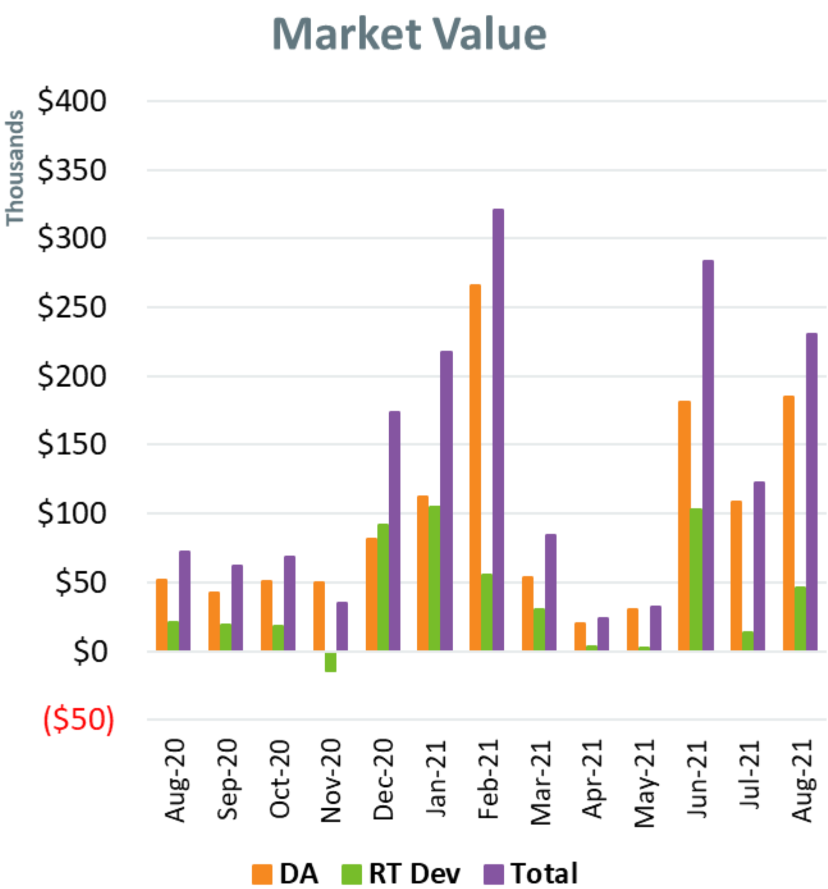
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - August 2021 NCPC payments totaled $2.3M over the period, down $0.5M from July 2021 and down $1.1M from August 2020
    - First Contingency payments totaled $1.9M, down $0.3M from July 2021
      - $1.8M paid to internal resources, down $0.3M from July
        - » $263K charged to DALO, $836K to RT Deviations, $750K to RTLO*
      - $37K paid to resources at external locations, up $16K from July
        - » $24K charged to DALO at external locations, $12K to RT Deviations
    - Second Contingency payments totaled $35K, down $276K from July
    - Distribution payments totaled $355K, up $61K from July
  - NCPC payments over the period as percent of Energy Market value were 0.4%

* NCPC types reflected in the First Contingency Amount allocated to RTLO: Dispatch Lost Opportunity Cost (DLOC) - $290K; Rapid Response Pricing (RRP) Opportunity Cost - $421K; Posturing - $38K; Generator Performance Auditing (GPA) - $0K

Price Responsive Demand (PRD) Energy Market Activity by Month





Note: DA and RT (deviation) MWh are settlement obligations and reflect appropriate gross-ups for distribution losses.

Highlights

- Remaining production cost preliminary results for the 2021 Economic Study (Future Grid Reliability Study) will be discussed at a special September 17 Planning Advisory Committee meeting
- RC to vote on the FCA 16 ICR and Related Values at their September 21 meeting
- 2022 ARA assumption discussions to commence at the PSPC on September 9
- The first Load Forecast Committee meeting to discuss the 2022 load forecast will be held on September 24
- Regional System Plan Public Meeting will be held virtually on October 6, and registration is now open
- Four Attachment K revisions are in various stages of development

Forward Capacity Market (FCM) Highlights

- CCP 12 (2021-2022)
  - Third and final annual reconfiguration auction (ARA3) was held on March 1-3, and results were posted on March 29
- CCP 13 (2022-2023)
  - Second annual reconfiguration auction (ARA2) will be held on August 2-4, and results will be posted no later than September 1
  - Development of ICR-Related Values assumptions to commence at the September 9 PSPC meeting; FERC filing to be made by November 30
- CCP 14 (2023-2024)
  - First annual reconfiguration auction (ARA1) was held on June 1-3, and results were posted June 30
  - Development of ICR-Related Values assumptions to commence at the September 9 PSPC meeting; FERC filing to be made by November 30
- CCP 15 (2024-2025)
  - Auction results were filed with FERC on February 26 and FERC approved on June 24
  - Development of ICR-Related Values assumptions to commence at the September 9 PSPC meeting; FERC filing to be made by November 30

CCP – Capacity Commitment Period

FCM Highlights, cont.

- CCP 16 (2025-2026)
  - FCA 16 will model the same zones as FCA 15
    - Export-constrained zones: Northern New England, and Maine nested inside Northern New England
    - Import-constrained zones: Southeast New England
  - A summary of permanent and retirement de-list bids was posted on March 17, and a summary of substitution auction demand bids was posted on April 30
    - These summaries were reposted on June 11 to reflect de-list bid withdrawals made after the Internal Market Monitor reissued its determinations based on the FERC-accepted CONE, Net CONE and Capacity Performance Payment Rate for FCA 16
      - The bid withdrawal Tariff provision that FERC accepted was for FCA 16 only
    - New Capacity Qualification is ongoing
  - ICR and Related Values development continues and discussions regarding assumptions and results are being held at the PSPC; on track for an RC vote on September 21

CONE – Cost of New Entry

Load Forecast

- Efforts continue to enhance load forecast models and tools to improve day-ahead and long-term load forecast performance
- Efforts to expand/improve the transportation electrification forecast for CELT 2022 have commenced
- The first Load Forecast Committee meeting for CELT 2022 will be held on September 24

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

- The ISO began one-on-one discussions with each QTPS that participated in the Boston 2028 RFP where QTPS specific questions regarding their proposals and/or the process can be discussed
- The lessons-learned process, with respect to competitive transmission solutions, was discussed at the October PAC meeting
- Stakeholder feedback was discussed at the 12/16/20 PAC meeting, and initial ISO responses were discussed at the 2/17/21 PAC meeting
- At the 4/14/21 PAC meeting, the ISO provided its plans for the remaining open items
- On 5/3/21, the ISO issued a memo to the PAC summarizing next steps in the process
- The ISO held discussions on the associated Tariff changes at the 7/14/21 and 8/24/21 TC meetings. The next discussion is scheduled for the 9/28/21 TC meeting.
- The first discussion at the RC is scheduled for 9/21/21

Highlights

- The lowest 50/50 and 90/10 Fall Operable Capacity Margins are projected for week beginning September 25, 2021.

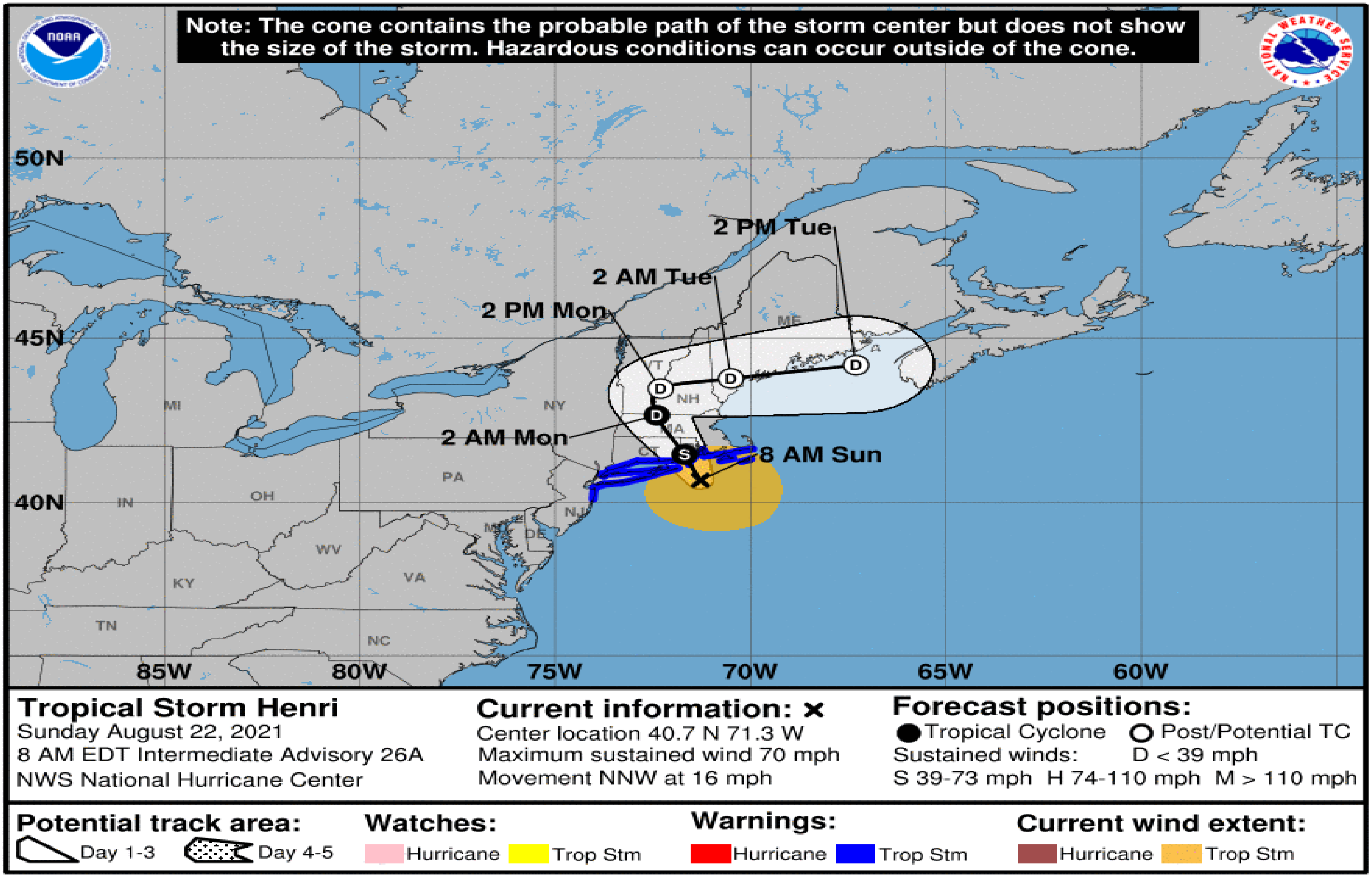
- The lowest 50/50 and 90/10 Preliminary Winter Operable Capacity Margins are projected for week beginning January 8, 2022.

Tropical Storm Henri

Tropical Storm Henri – Overview

- Tropical Storm Henri was minimally impactful to the Bulk Electric System
- ISO, LCC's, Transmission, Distribution, Generation, Demand entities were all well prepared for the storm
- MLCC#2 was issued at 15:00 on 8/20 in preparation for the storm and was canceled at 12:00 on 8/23; No other emergency procedures were required
- Generation Resources were minimally impacted by the storm; No major generation resources tripped during the storm.
- Original Peak Load forecast was 17,100 MW at 19:00 on 8/22 and the actual was 16,440 MW at 19:00
- Minimal load lost during the storm with approximately 140,000 customer outages at the peak of the storm with most in Rhode Island where the storm made landfall
- Two 115kV transmission lines impacted during the storm, both restored on the same day

Forecasted Weather Conditions on Sunday



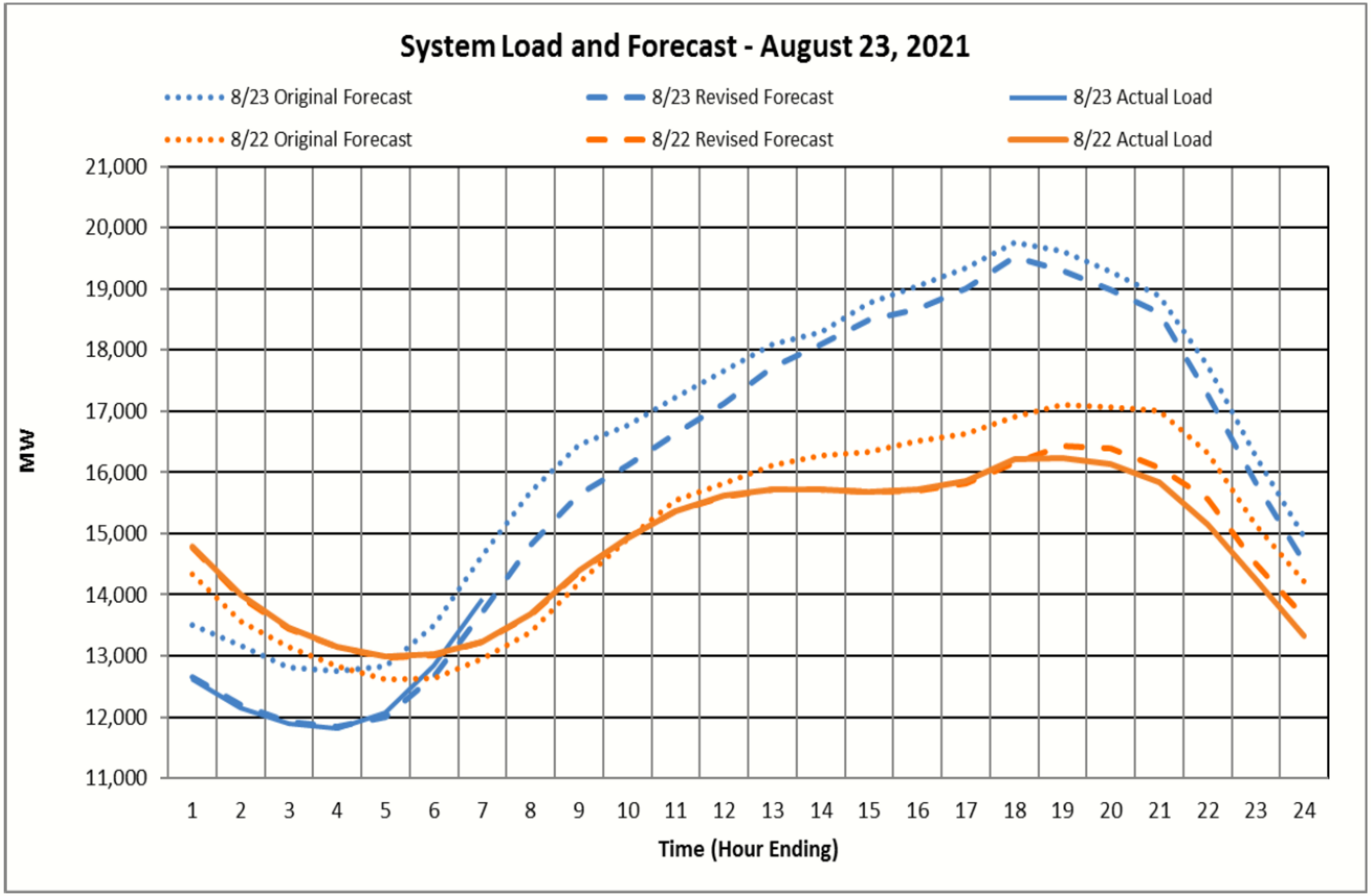
Communications for Henri

- Calls with M/LCC Heads prior to and during the storm
- Calls with NPCC and all NPCC Reliability Coordinators prior and during the storm
- Calls with Gas Pipelines and LNG resources for readiness prior to the storm
- Calls with Nuclear Plants prior to and during the storm
- Regular Communication with Regulatory contacts
- Generators surveyed via phone call to determine plans, readiness and set expectations for potential abnormal operations
- Staffing enhanced at the ISO and LCCs; ISO added onsite engineering, building and communications infrastructure and IT staffs at the MCC and BCC

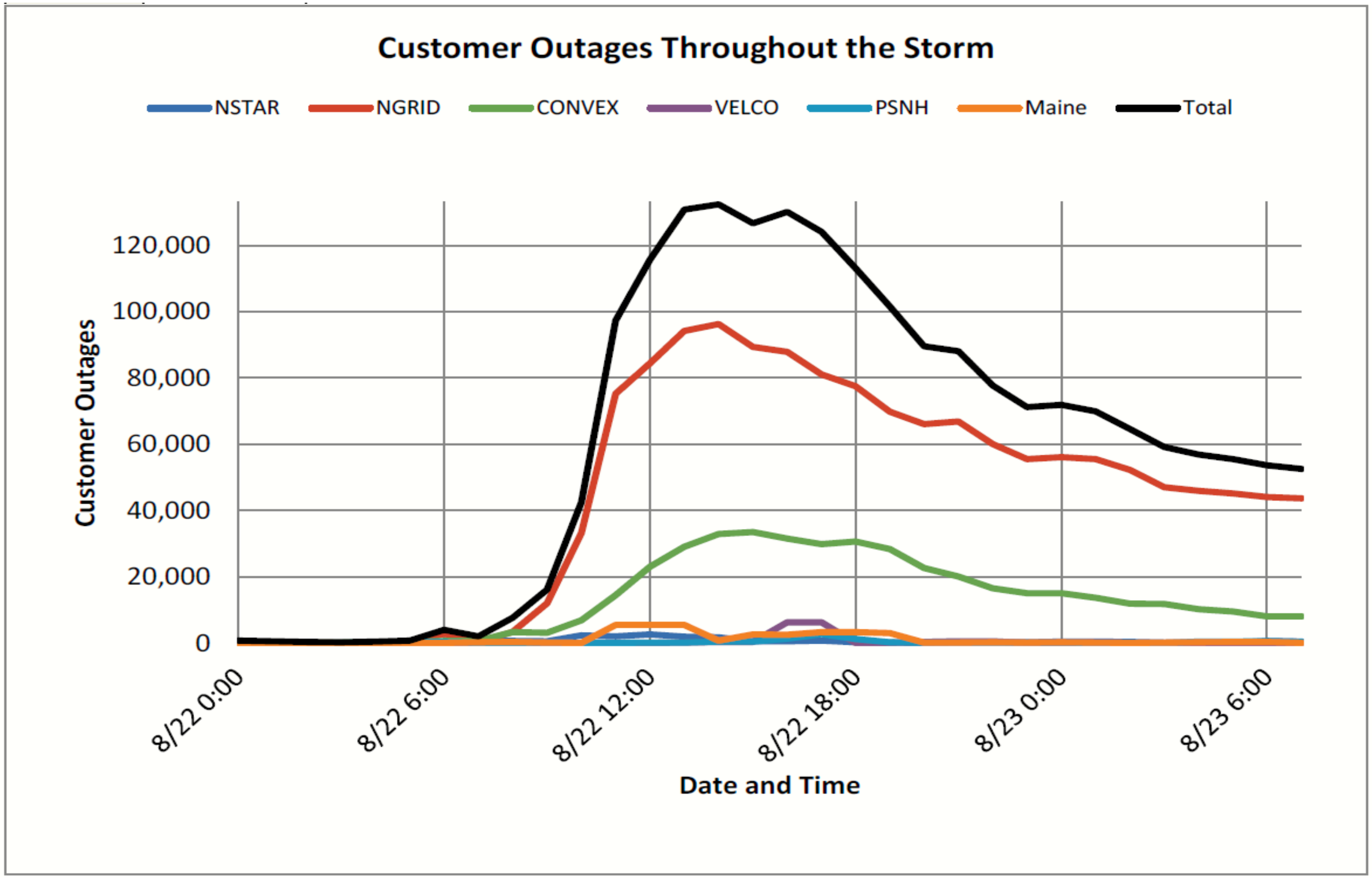
Actions taken by ISO New England

- M/LCC 2 – Abnormal Conditions Alert was declared at 15:00 on Friday 8/20 and canceled at 12:00 on Monday 8/23
  - Outages of generation and transmission recalled and or postponed if possible
- No supplemental commitments were required before or during the storm as the Day Ahead Commitments met all expected needs

Actual vs. Forecasted Load



Customer Outages by LCC



SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (3.8°F) Max: 96°F, Min: 62°F Precipitation: 6.98" – Above Normal Normal: 3.04"	Hartford	Temperature: Above Normal (2.1°F) Max: 95°F, Min: 53°F Precipitation: 4.28" - Above Normal Normal: 3.98"

Peak Load:	24,811 MW	August 12, 2021	18:00 (ending)

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

Procedure	Declared	Cancelled	Note
M/LCC 2	8/20/2021 15:00	8/23/2021 12:00	Severe Weather
M/LCC 2	8/25/2021 13:00	8/25/2021 22:00	Capacity

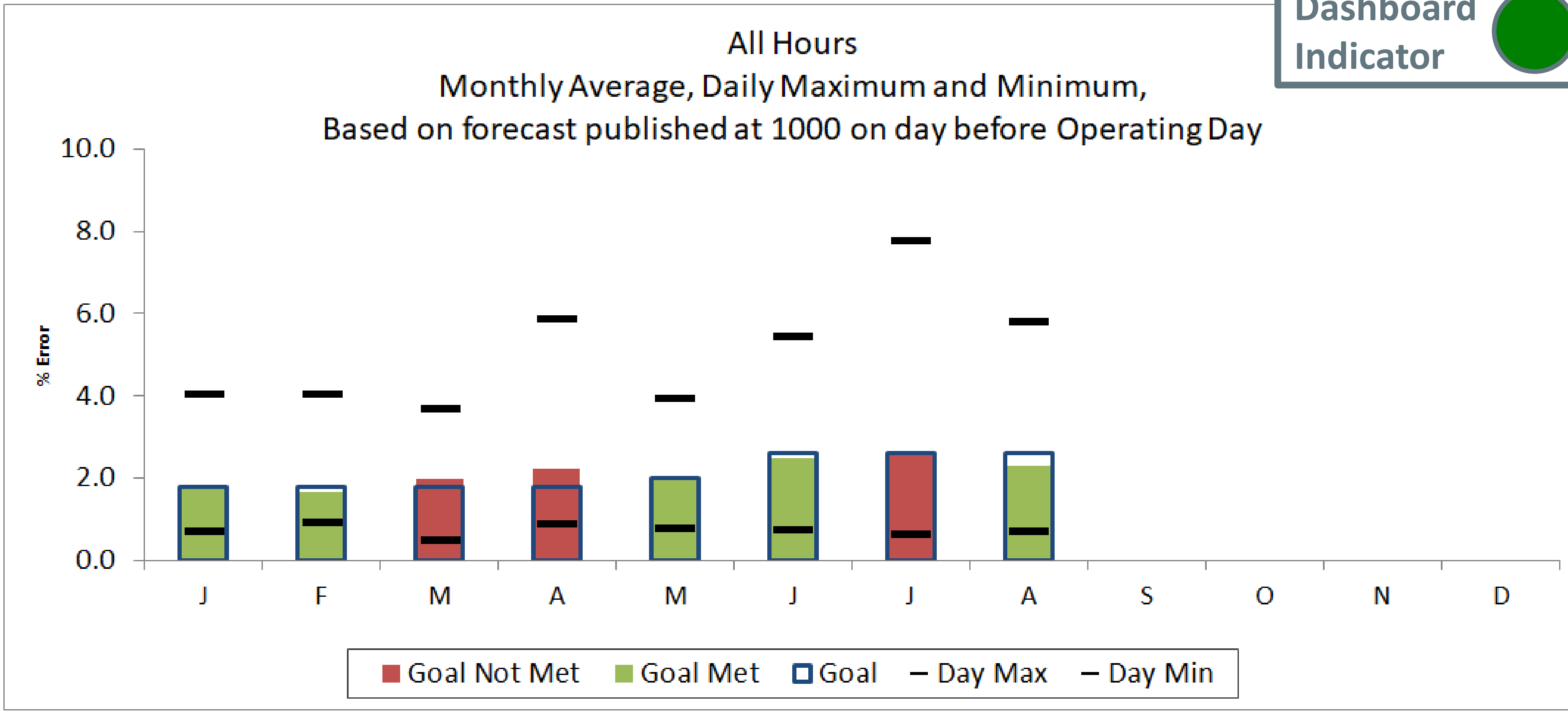
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
8/20	NYISO	527
8/24	PJM	1200
8/25	IESO	550

2021 System Operations - Load Forecast Accuracy

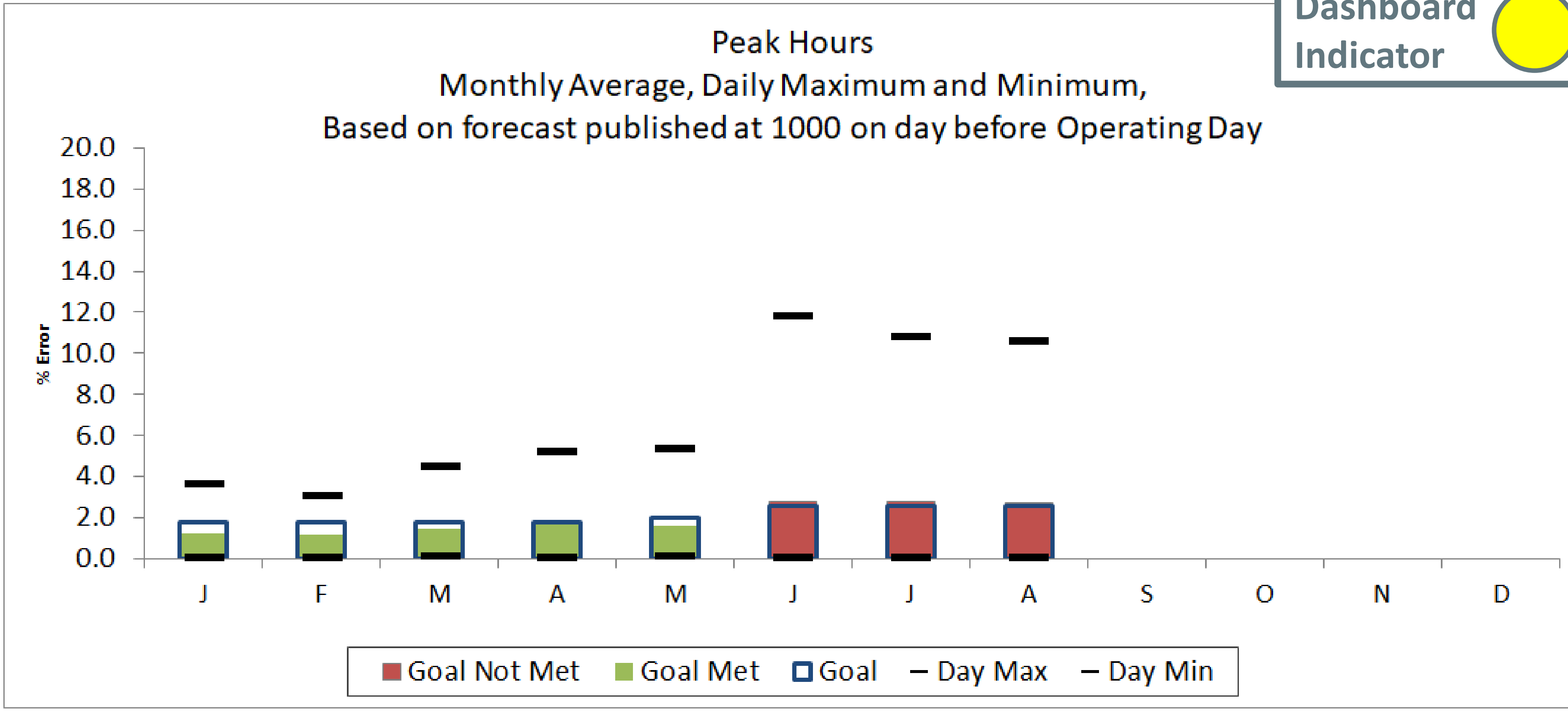
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.04	4.03	3.67	5.85	3.92	5.41	7.75	5.77					7.75
Day Min	0.70	0.92	0.49	0.88	0.77	0.73	0.63	0.71					0.49
MAPE	1.72	1.66	1.97	2.24	1.95	2.50	2.61	2.32					2.12
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60					

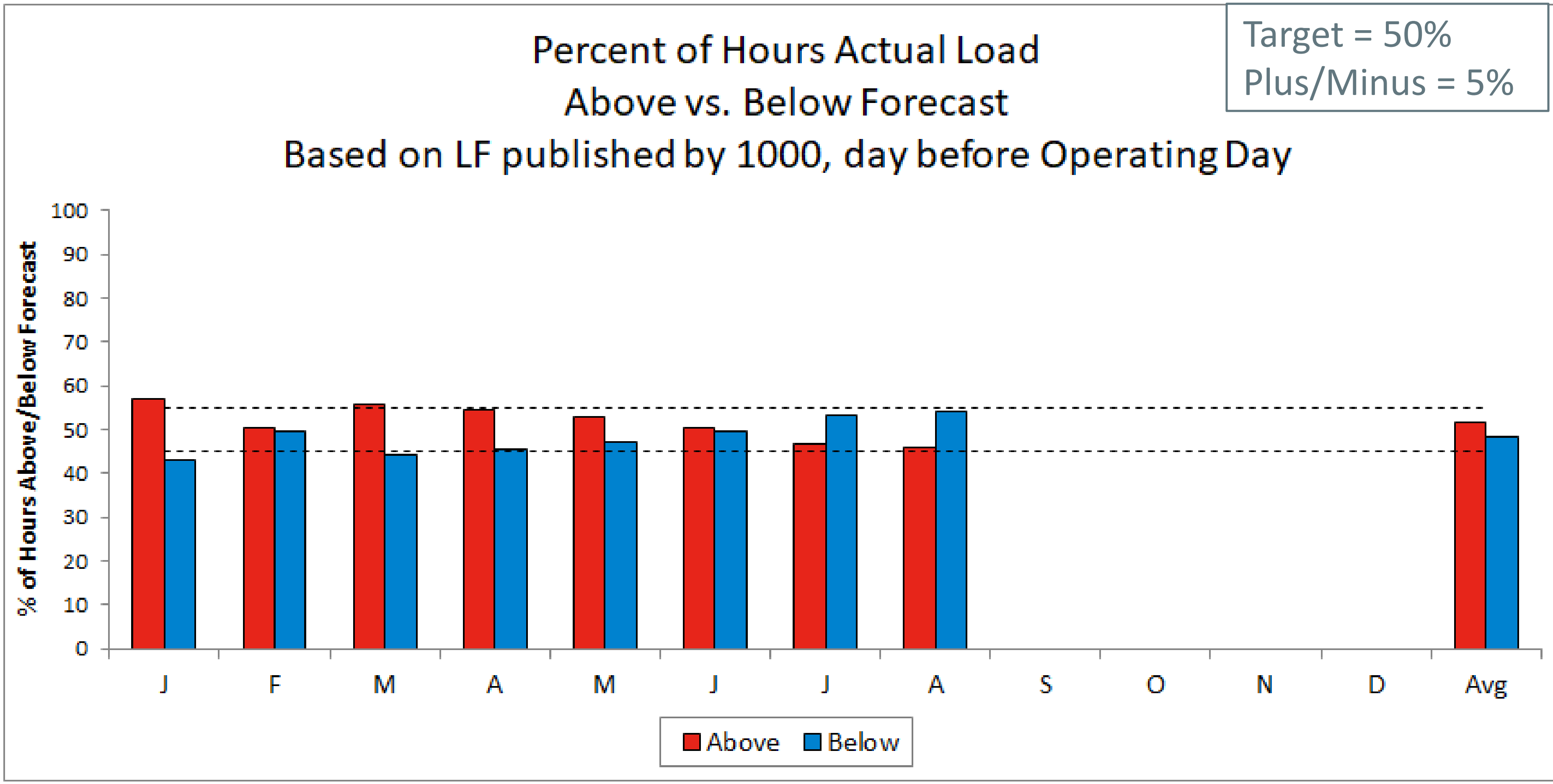
2021 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



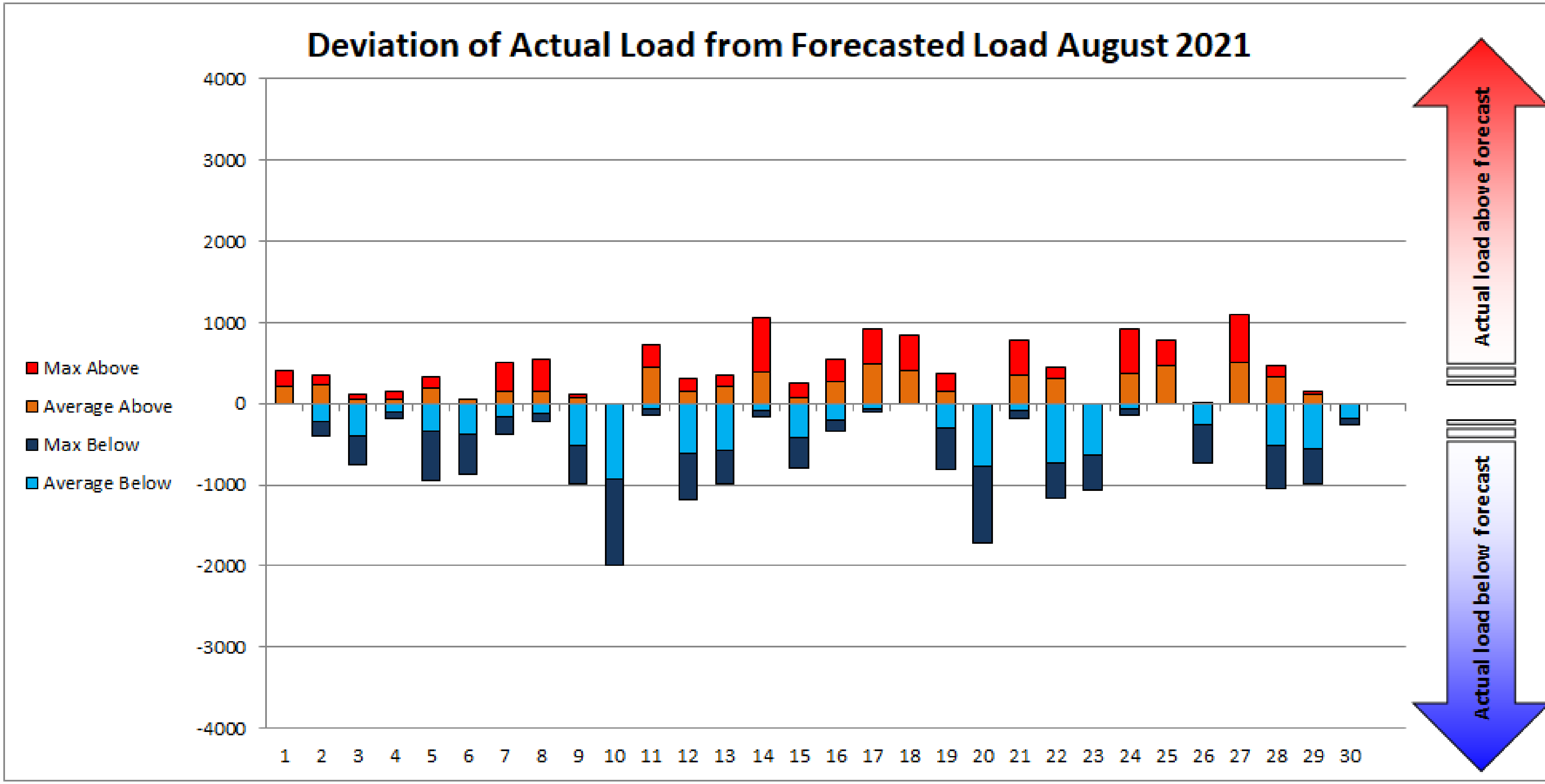
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	3.61	3.03	4.47	5.19	5.31	11.76	10.75	10.54					11.76
Day Min	0.02	0.06	0.08	0.03	0.11	0.04	0.05	0.01					0.01
MAPE	1.26	1.18	1.48	1.66	1.60	2.79	2.78	2.75					1.94
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60					

2021 System Operations - Load Forecast Accuracy cont.

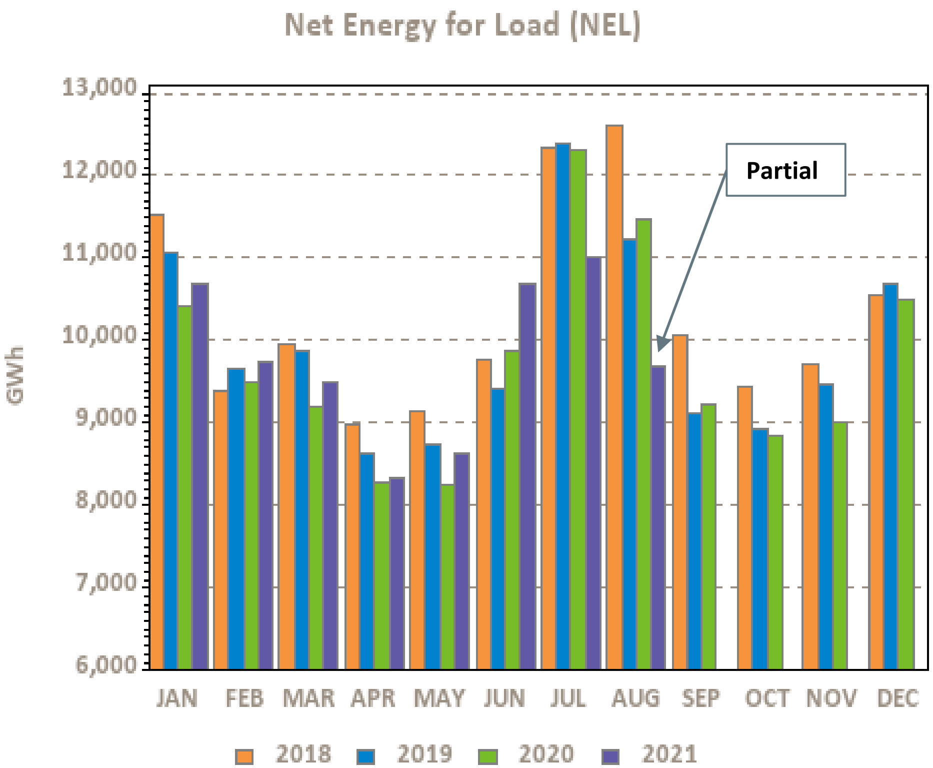


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	57.1	50.4	55.6	54.4	52.8	50.3	46.9	45.7					52
Below %	42.9	49.6	44.4	45.6	47.2	49.7	53.1	54.3					48
Avg Above	209.5	166.7	185.4	206.1	227.4	233.1	214.5	200.3					233
Avg Below	-147.6	-216.4	-188.0	-167.9	-146.8	-309.1	-348.1	-301.4					-348
Avg All	60	-25	30	40	61	-48	-122	-105					-13

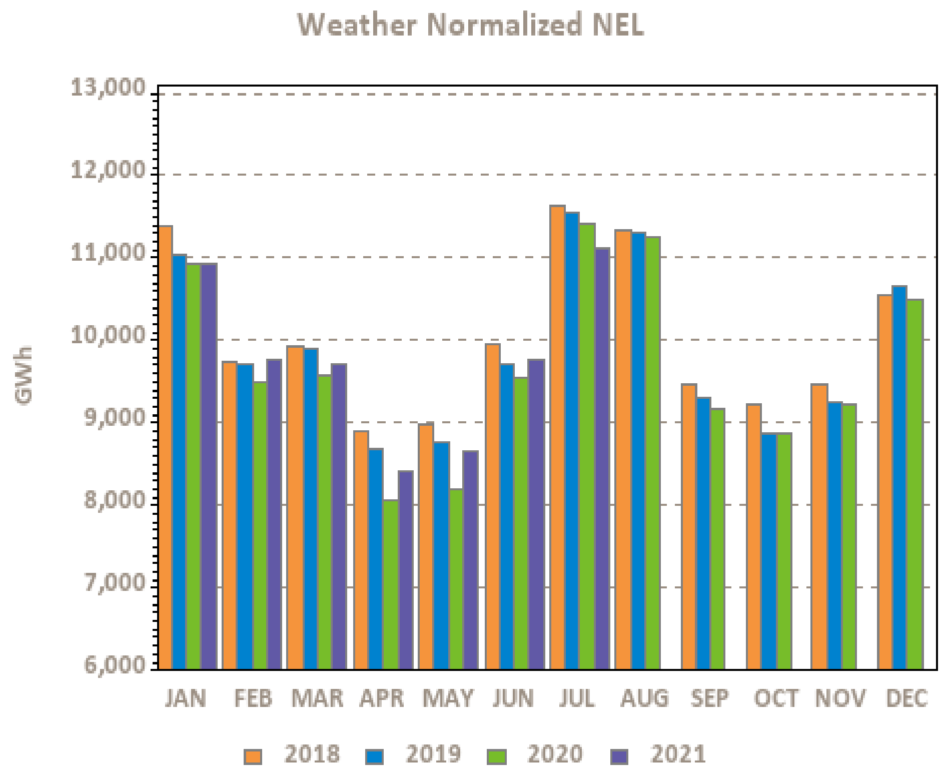
2021 System Operations - Load Forecast Accuracy cont.



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



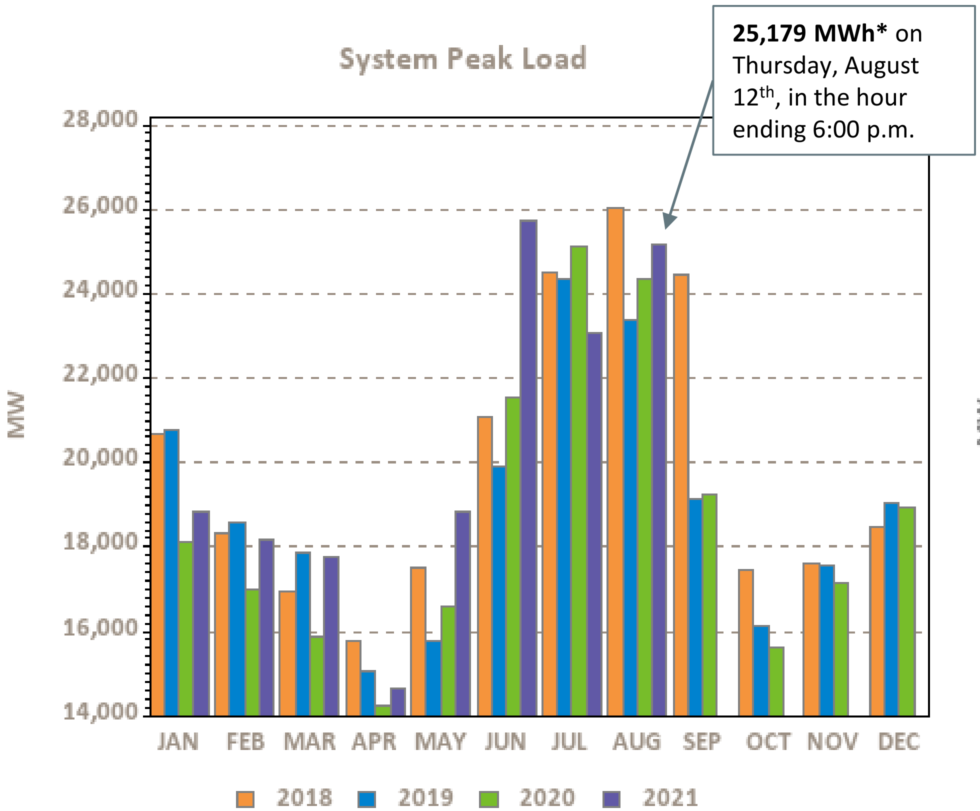
Ann Tot (TWh): 123.5 119.2 116.9 78.3



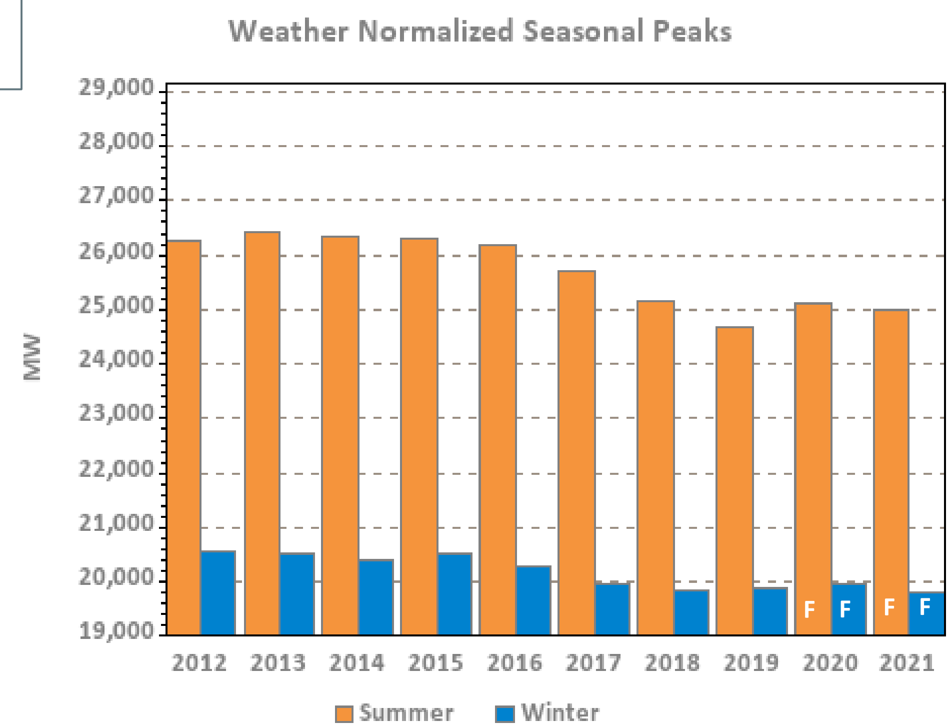
Ann Tot (TWh): 120.6 118.8 116.3 68.4

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

Monthly Peak Loads and Weather Normalized Seasonal Peak History



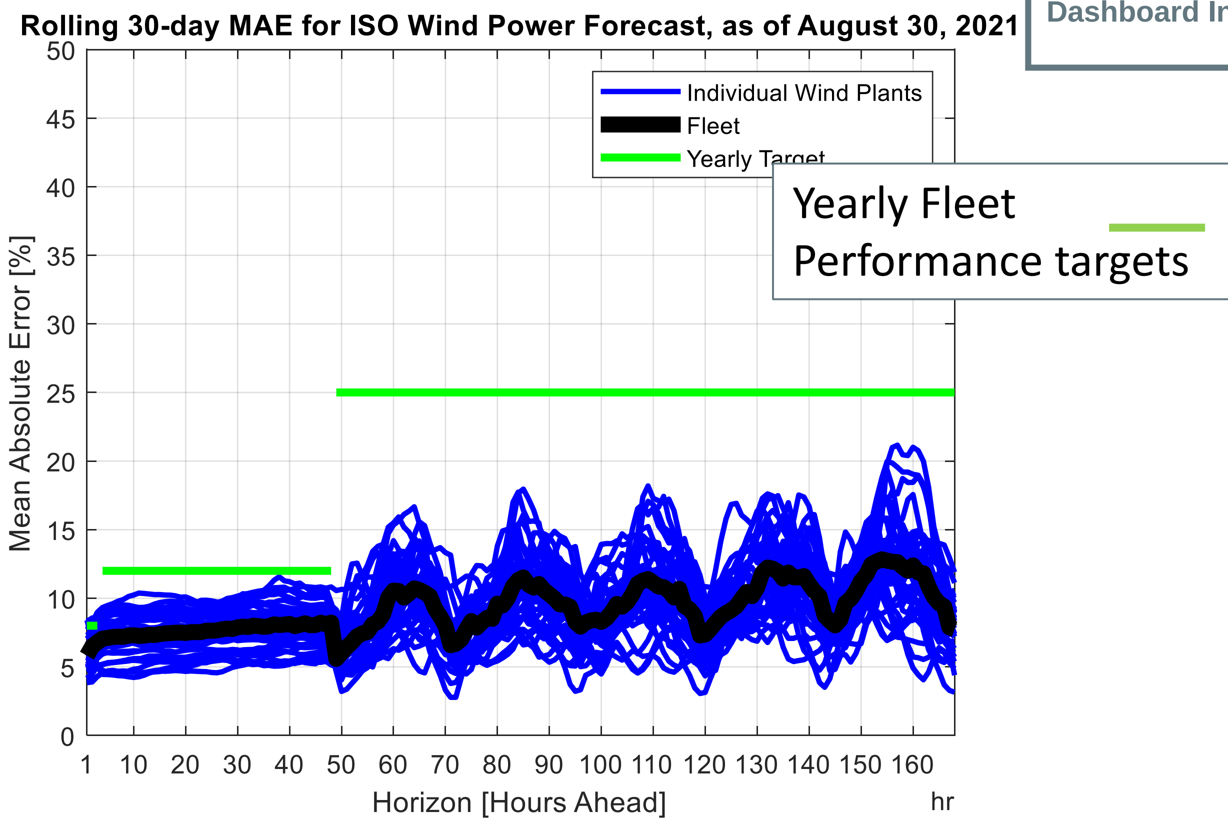
*Revenue quality metered value



Winter beginning in year displayed

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

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

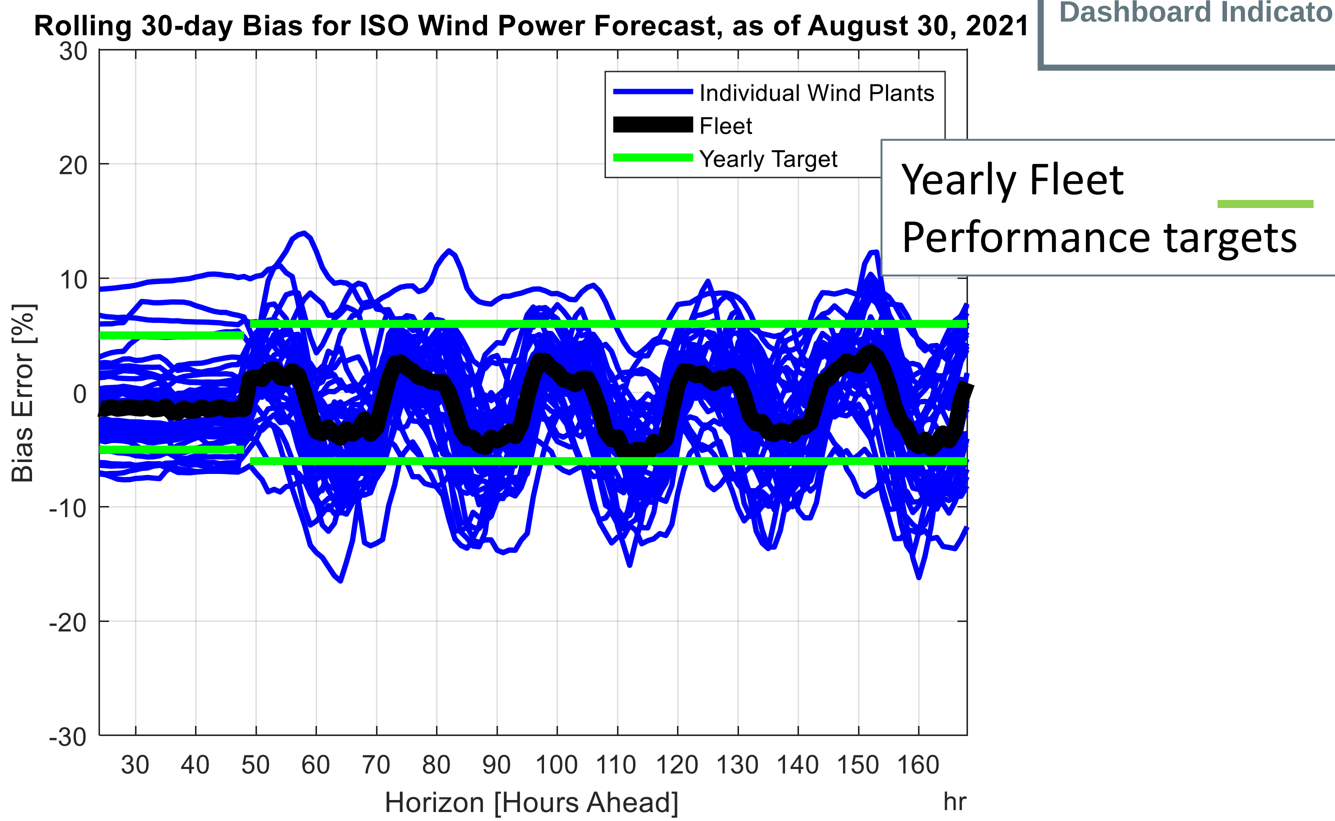


Dashboard Indicator

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

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

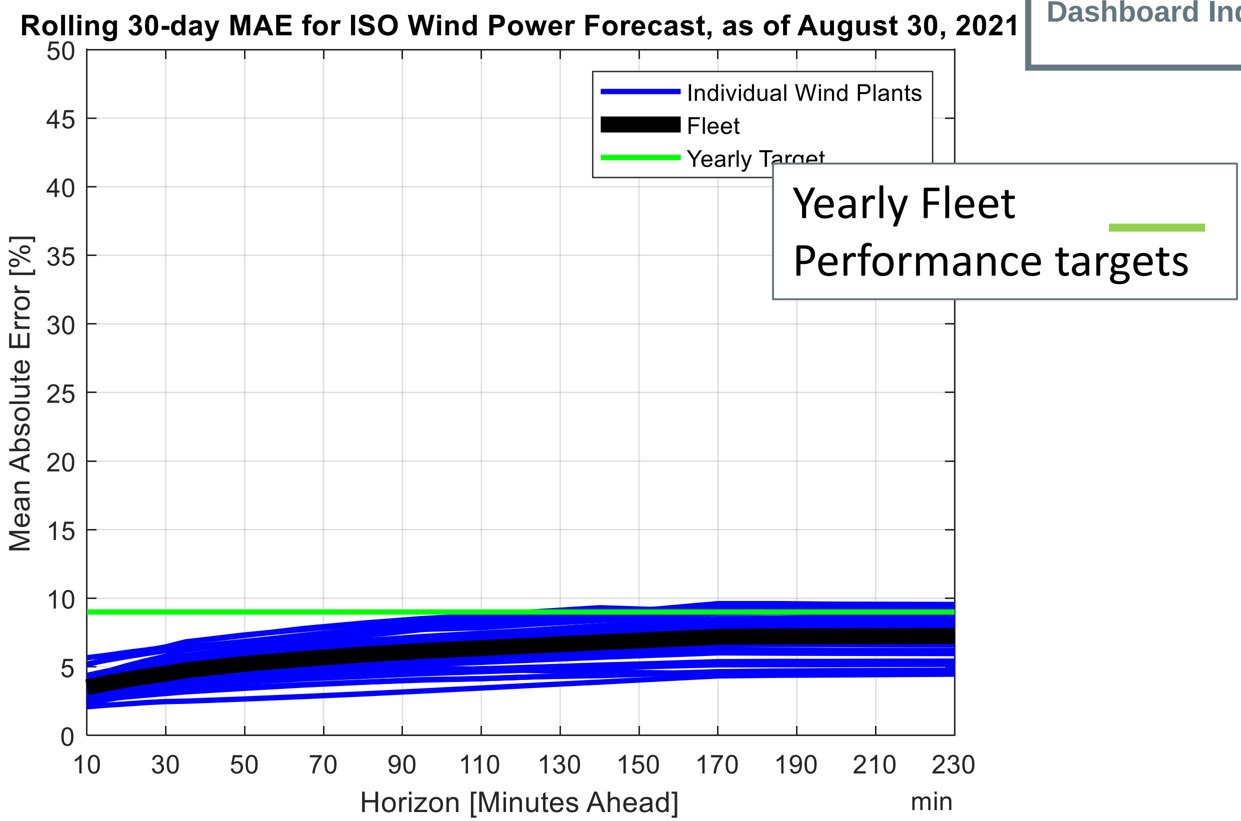
Dashboard Indicator



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

Wind Power Forecast Error Statistics: Short Term Forecast MAE

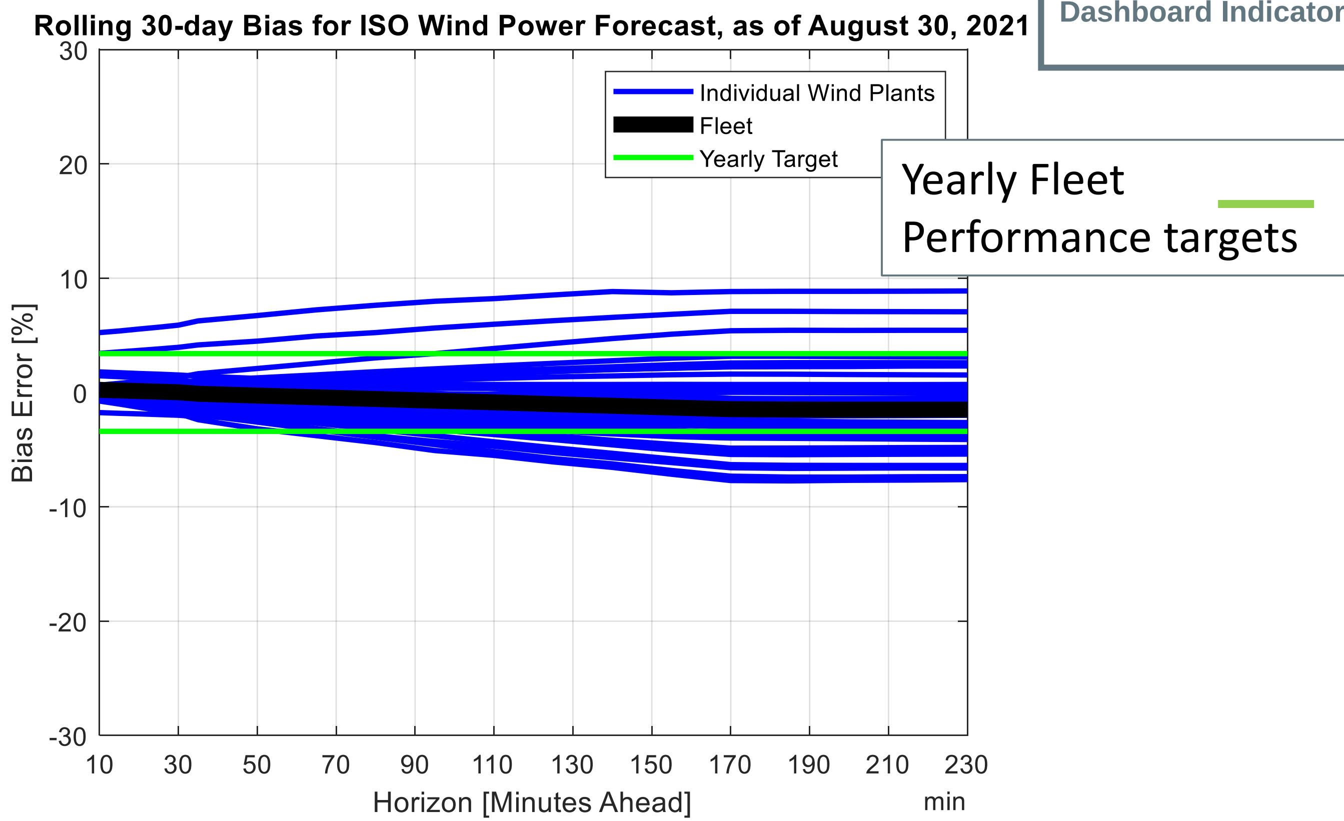
Dashboard Indicator



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

Wind Power Forecast Error Statistics: Short Term Forecast Bias

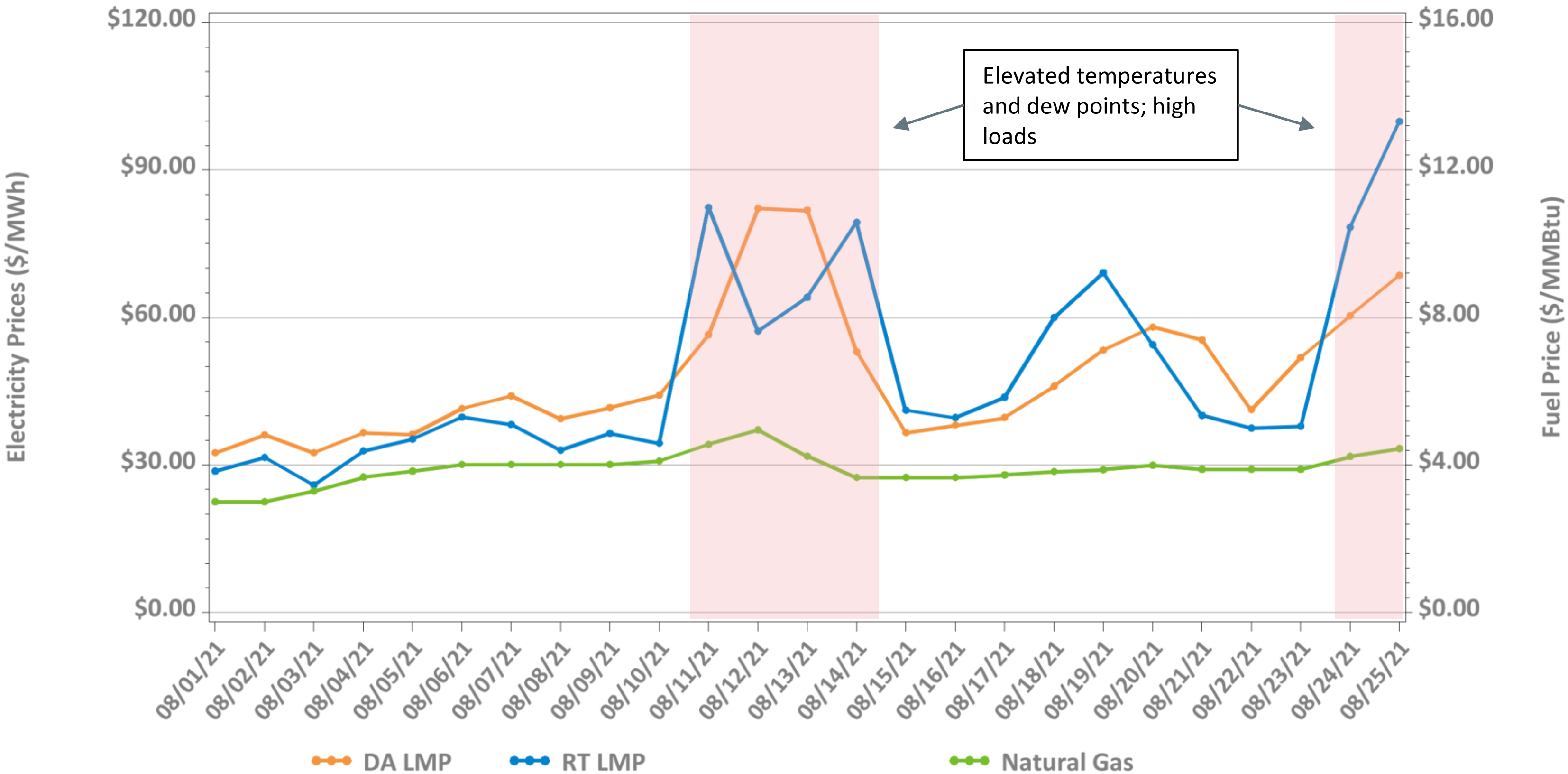
Dashboard Indicator



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

MARKET OPERATIONS

Daily Average DA and RT ISO-NE Hub Prices and Input Fuel Prices: August 1-25, 2021

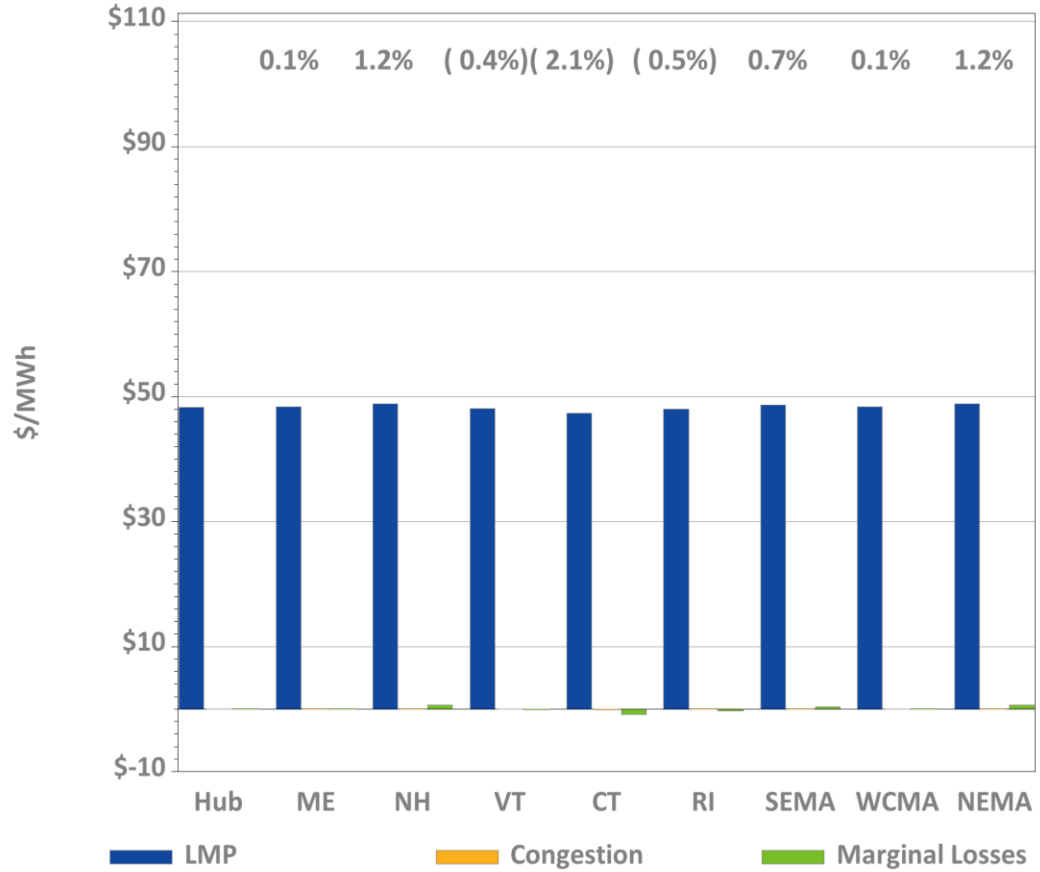


Underlying natural gas data furnished by:

ice Global markets in clear view

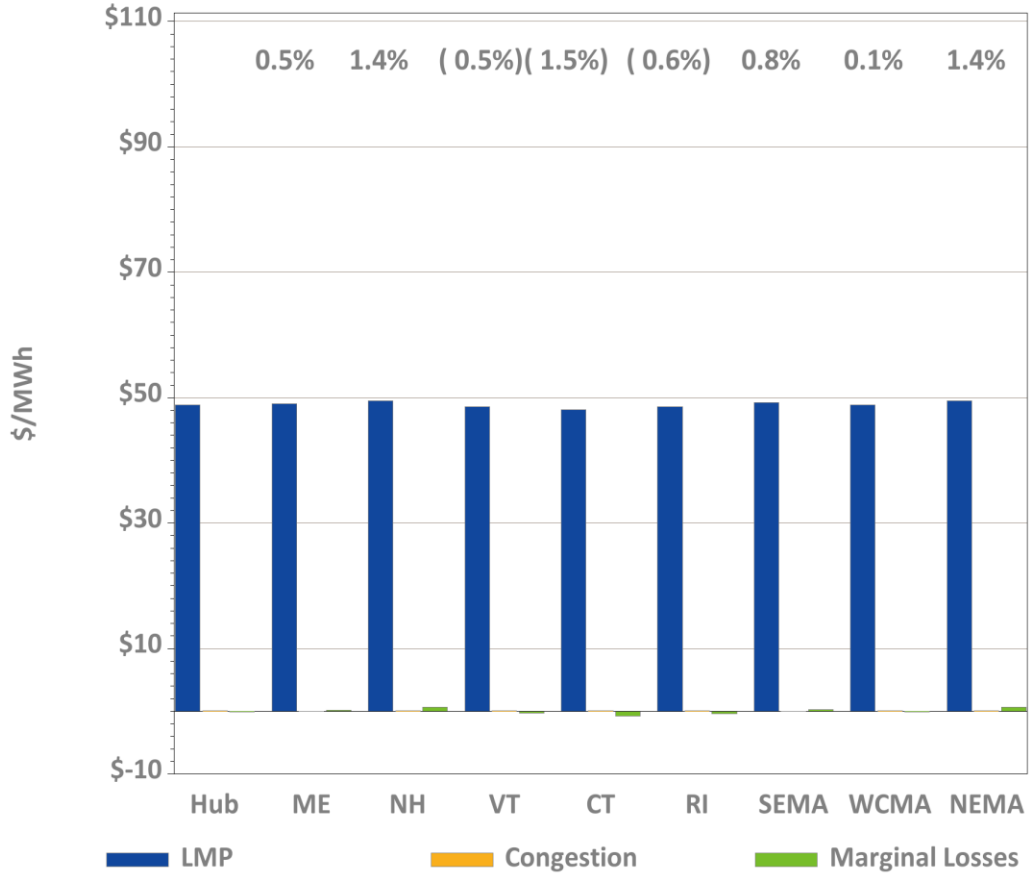
Average price difference over this period (DA-RT): $-0.54
Average price difference over this period ABS(DA-RT): $10.78
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 22%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, August 2021



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

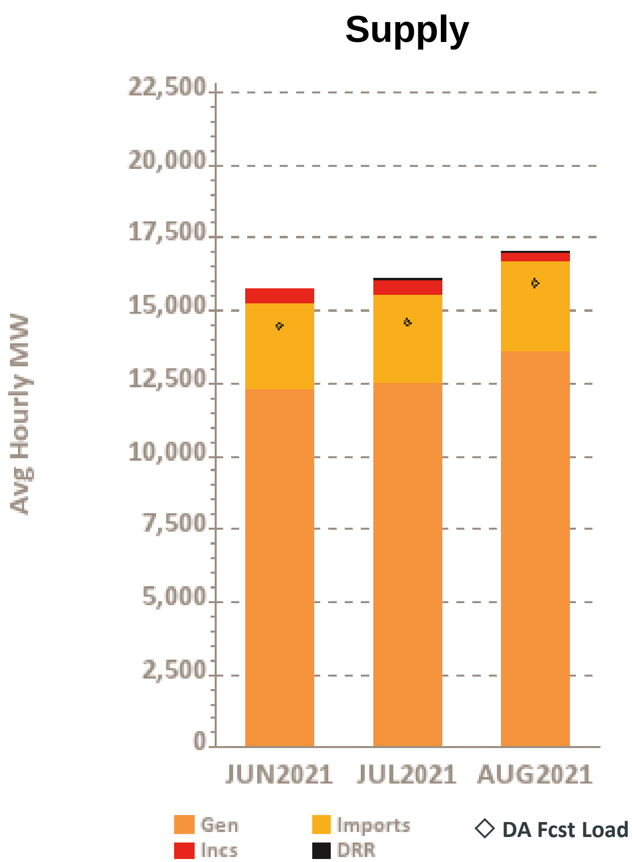
RT LMPs Average by Zone & Hub, August 2021

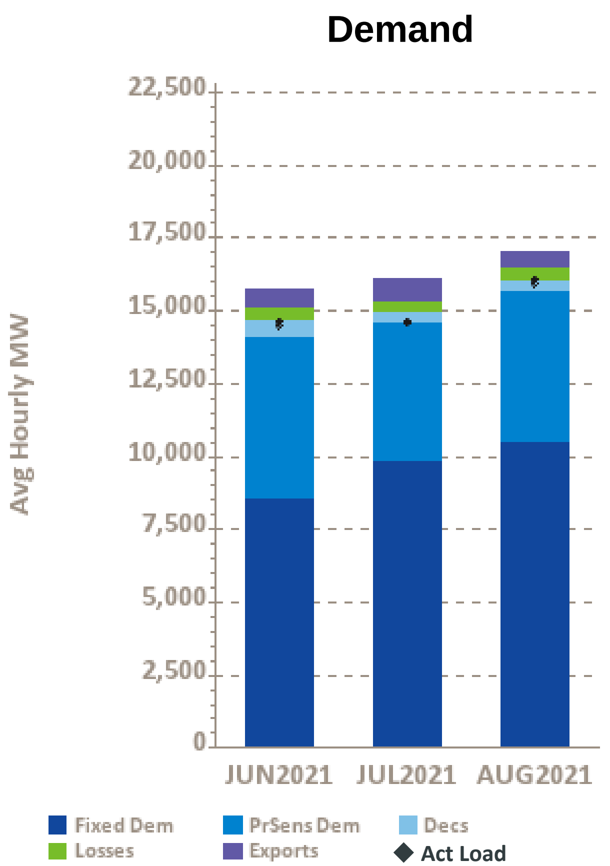


Definitions

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

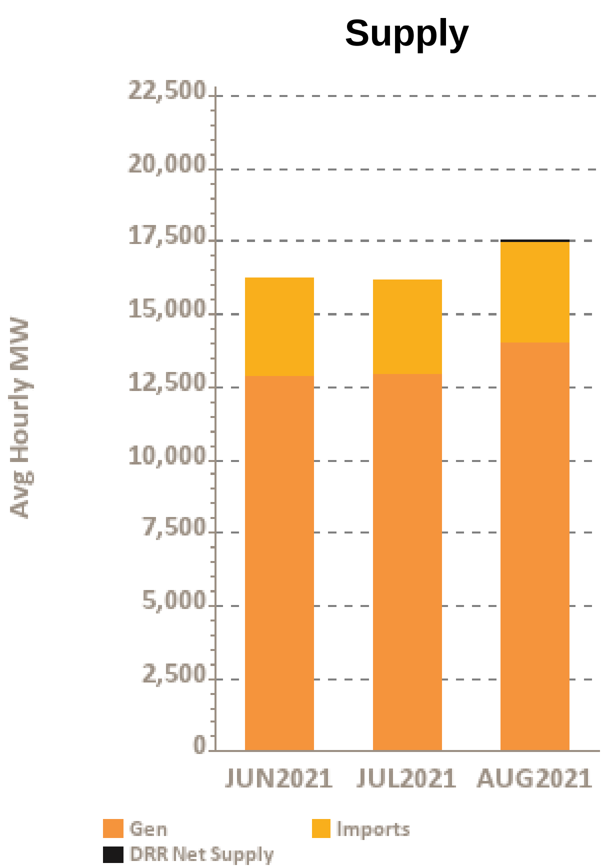


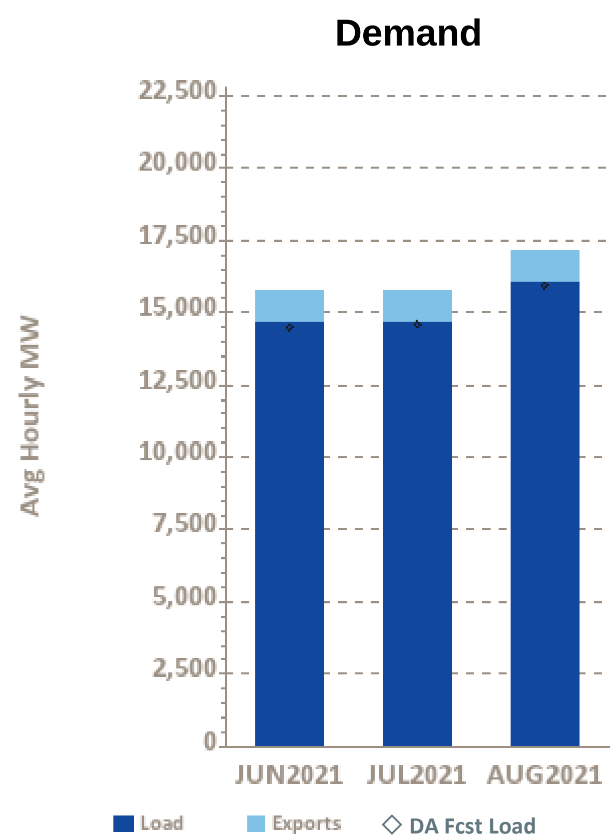


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load
DRR – Demand Response Resource

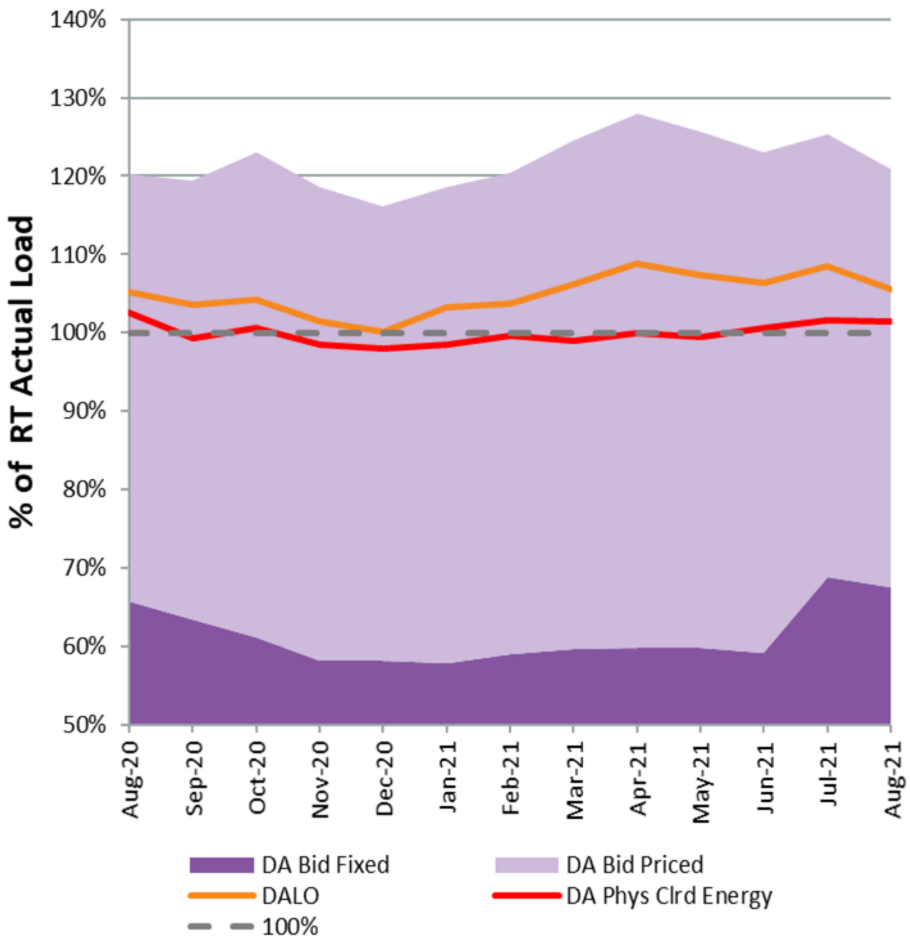
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

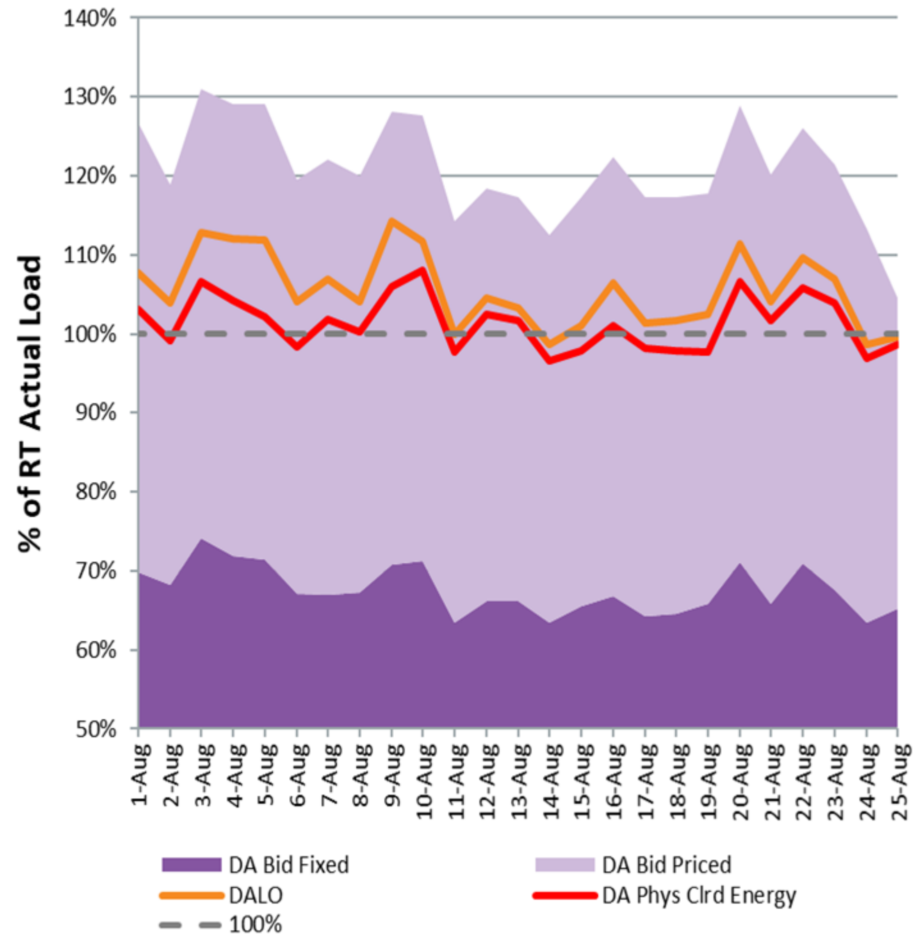
Components of RT Supply and Demand – Last Three Months





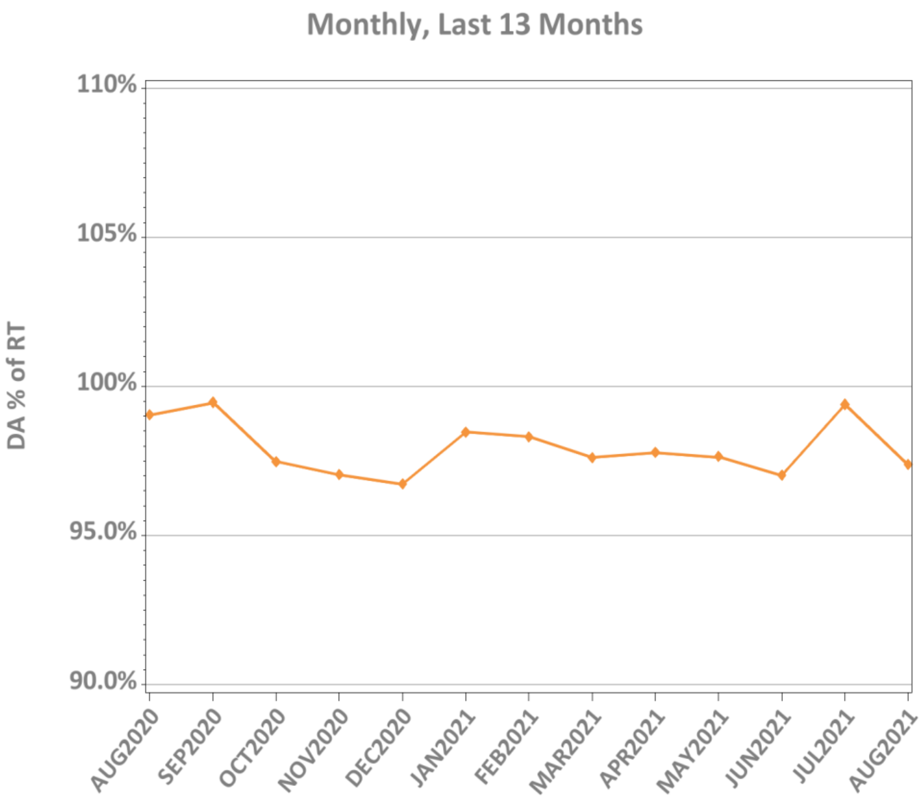
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

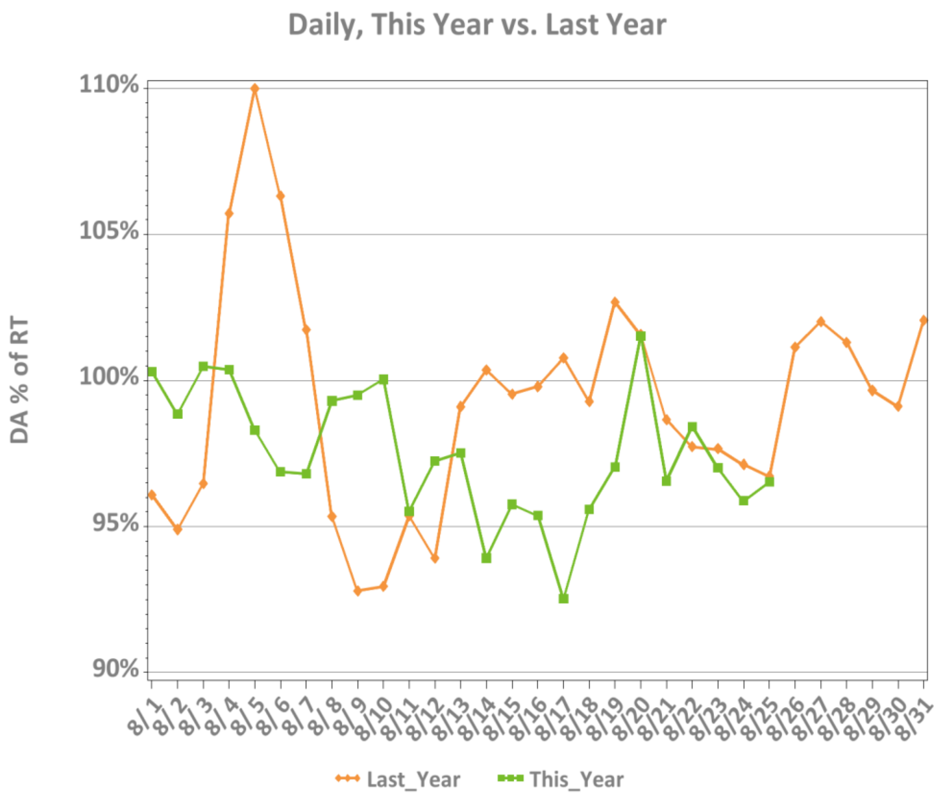




Note: Forecasted peak hour for each day is reflected in the above values. Shown for each day (chart on right) and then averaged for each month (chart on left). 'DA Bid' categories reflect load assets only (Virtual and export bids not reflected.)

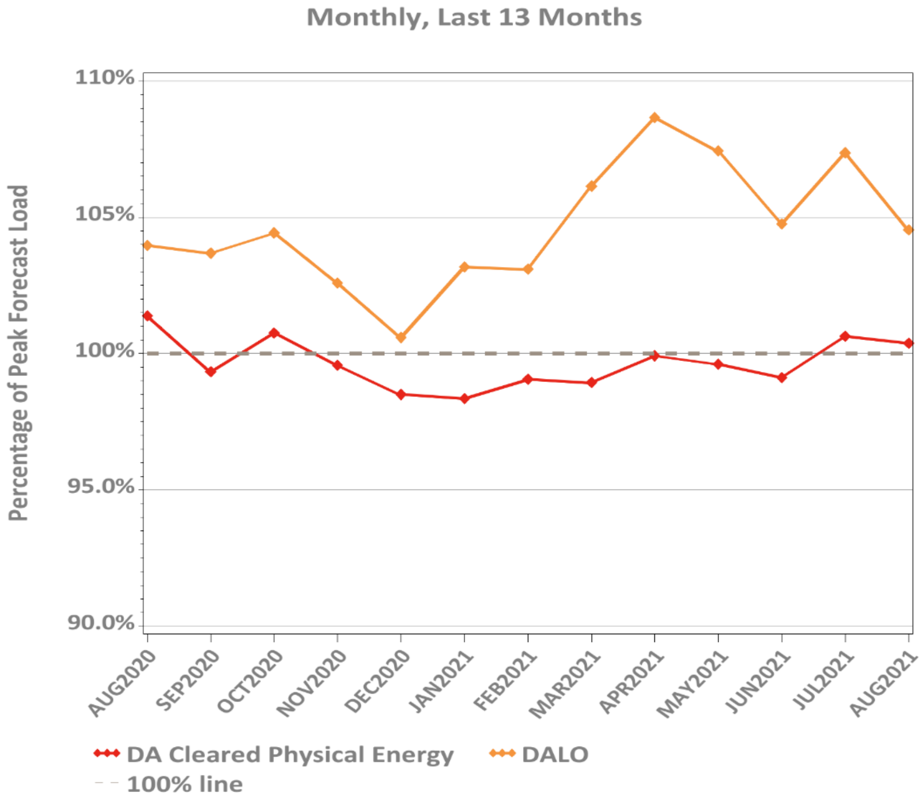
DA vs. RT Load Obligation: August, This Year vs. Last Year

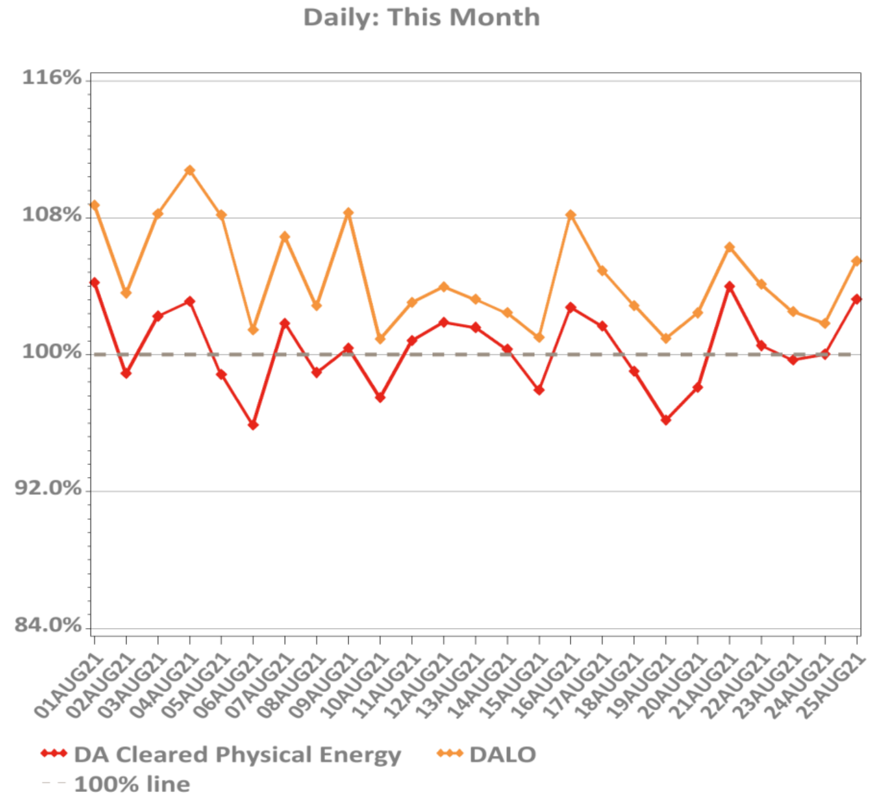




*Hourly average values

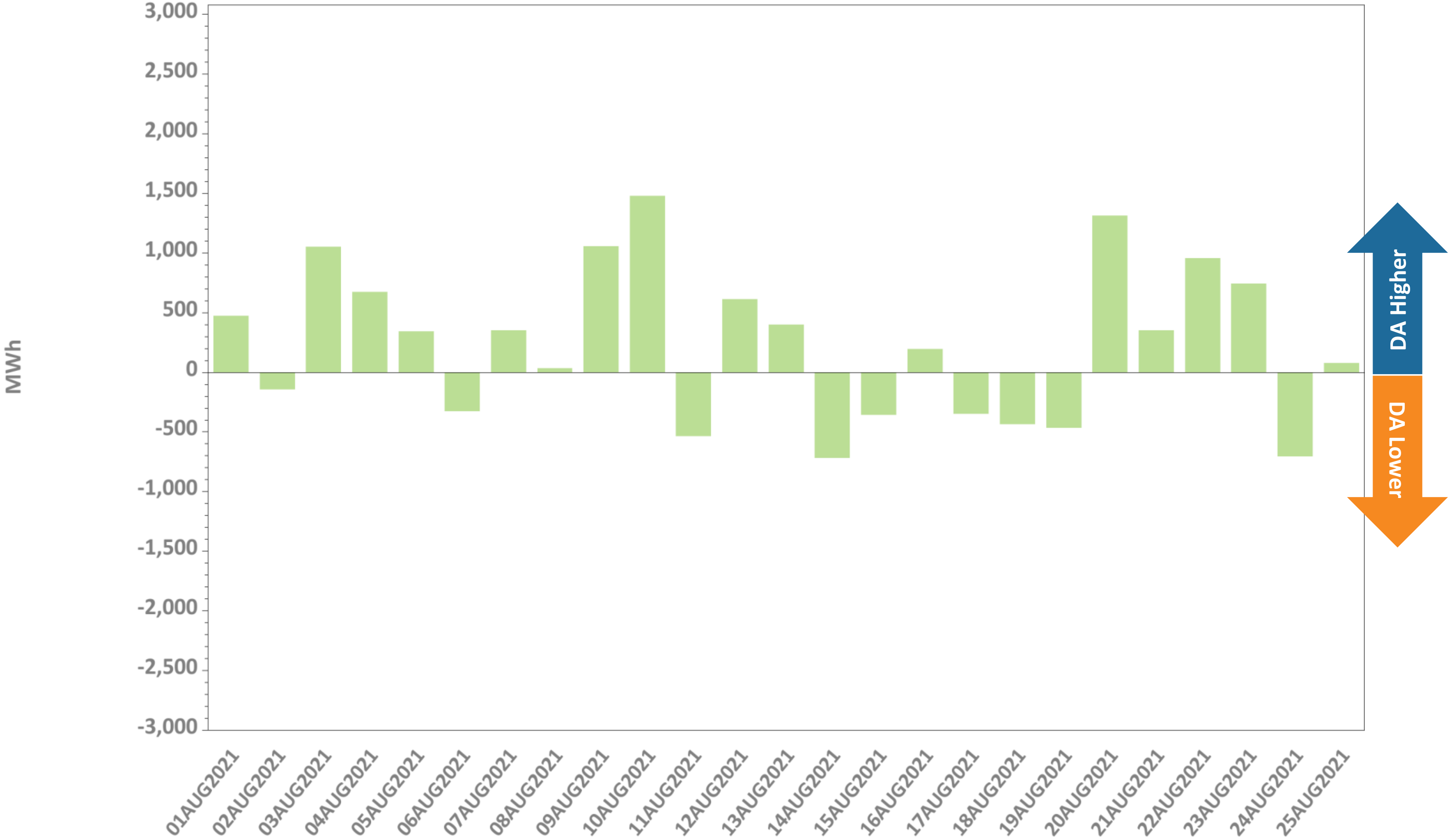
DA Volumes as % of Forecast in Peak Hour





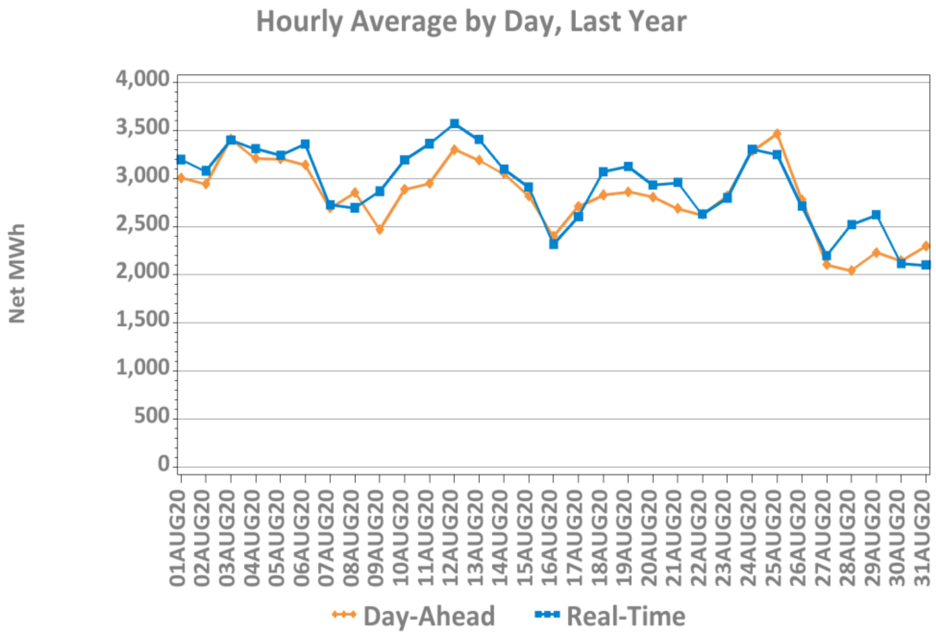
Note: There were no instances of system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) during August.

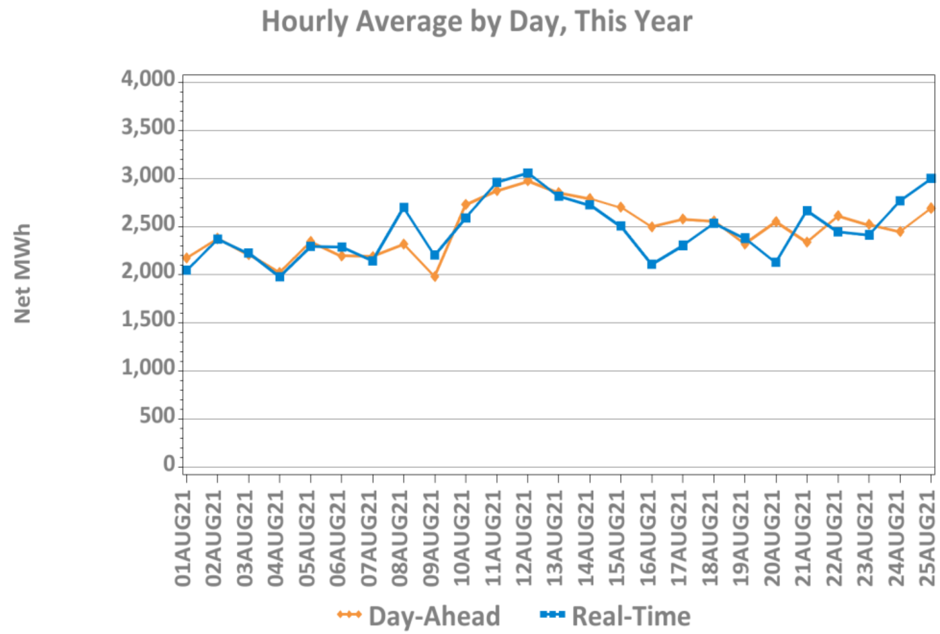
DA Cleared Physical Energy Difference from RT System Load at Forecasted Peak Hour*



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

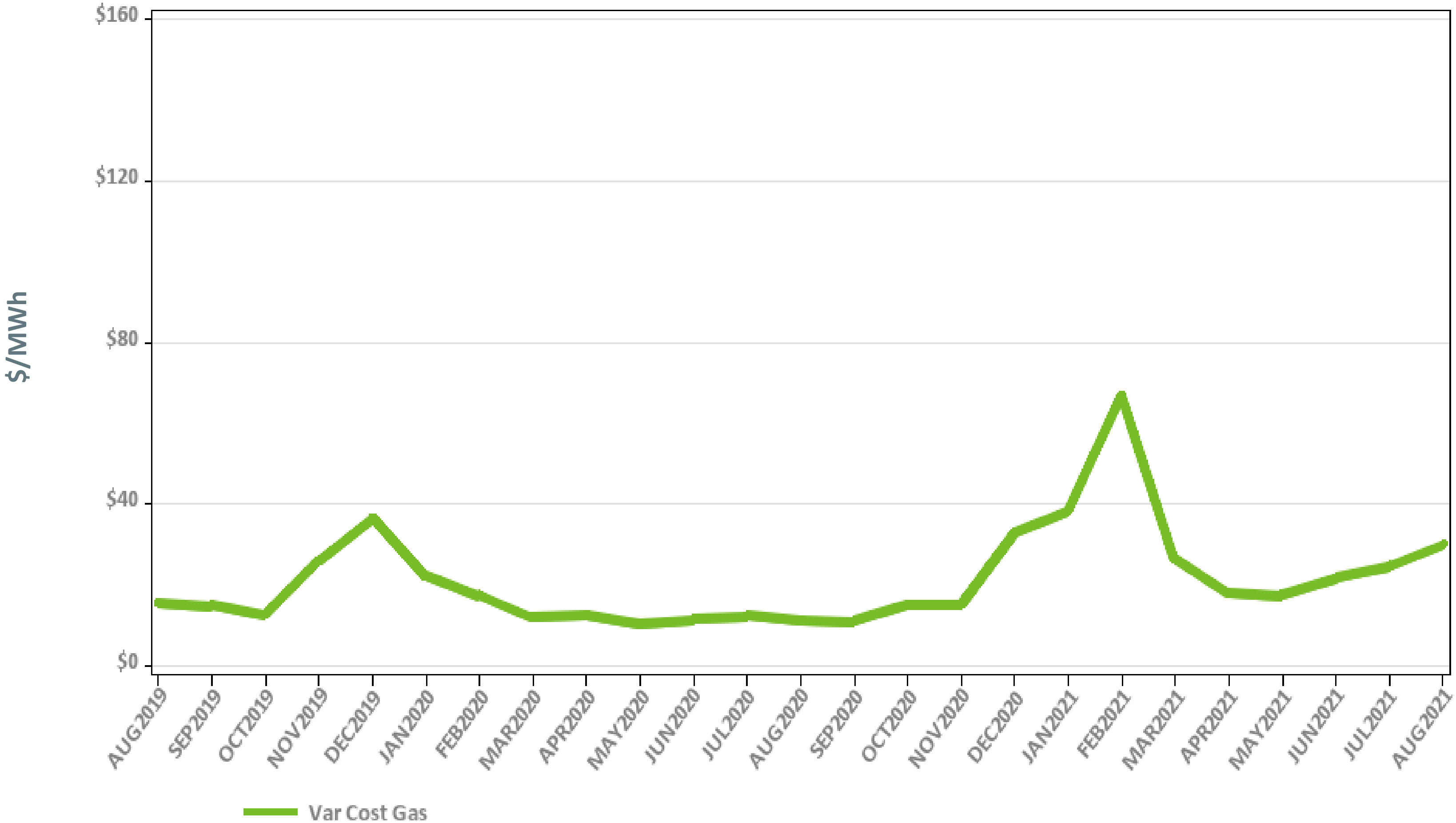
DA vs. RT Net Interchange August 2020 vs. August 2021





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

Variable Production Cost of Natural Gas: Monthly

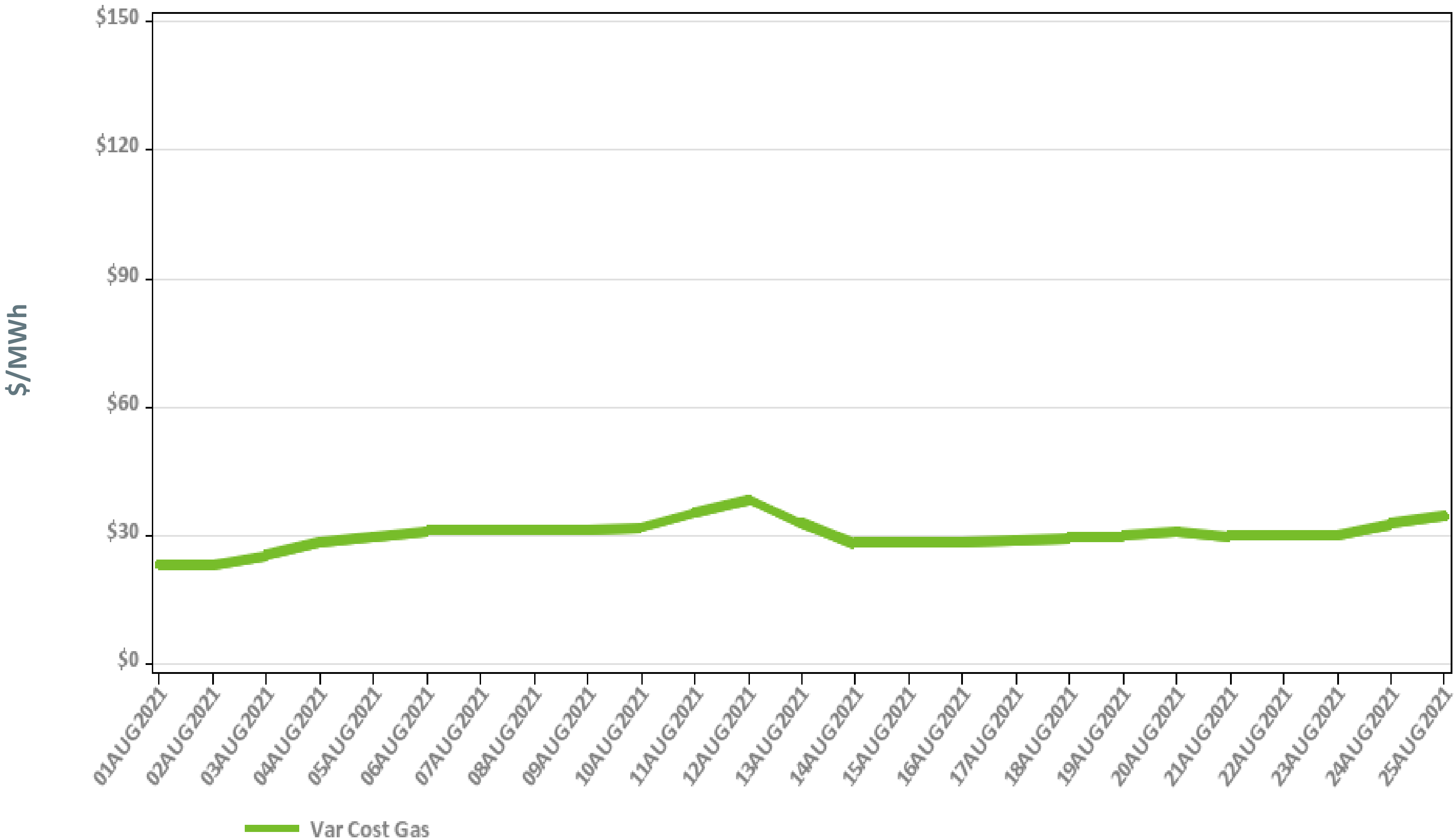


Underlying natural gas data furnished by:

ICE Global markets in clear view

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

Variable Production Cost of Natural Gas: Daily

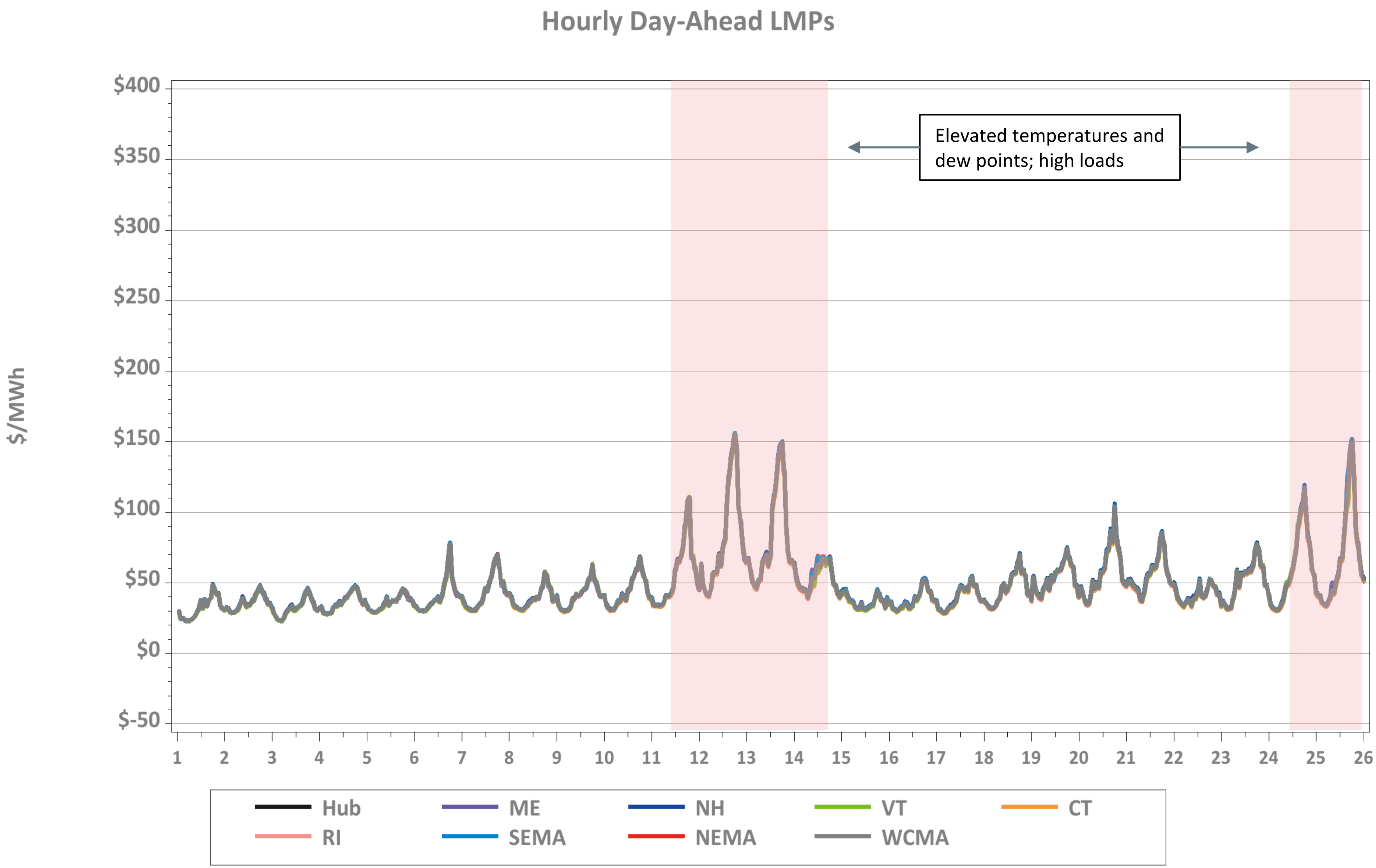


Underlying natural gas data furnished by:

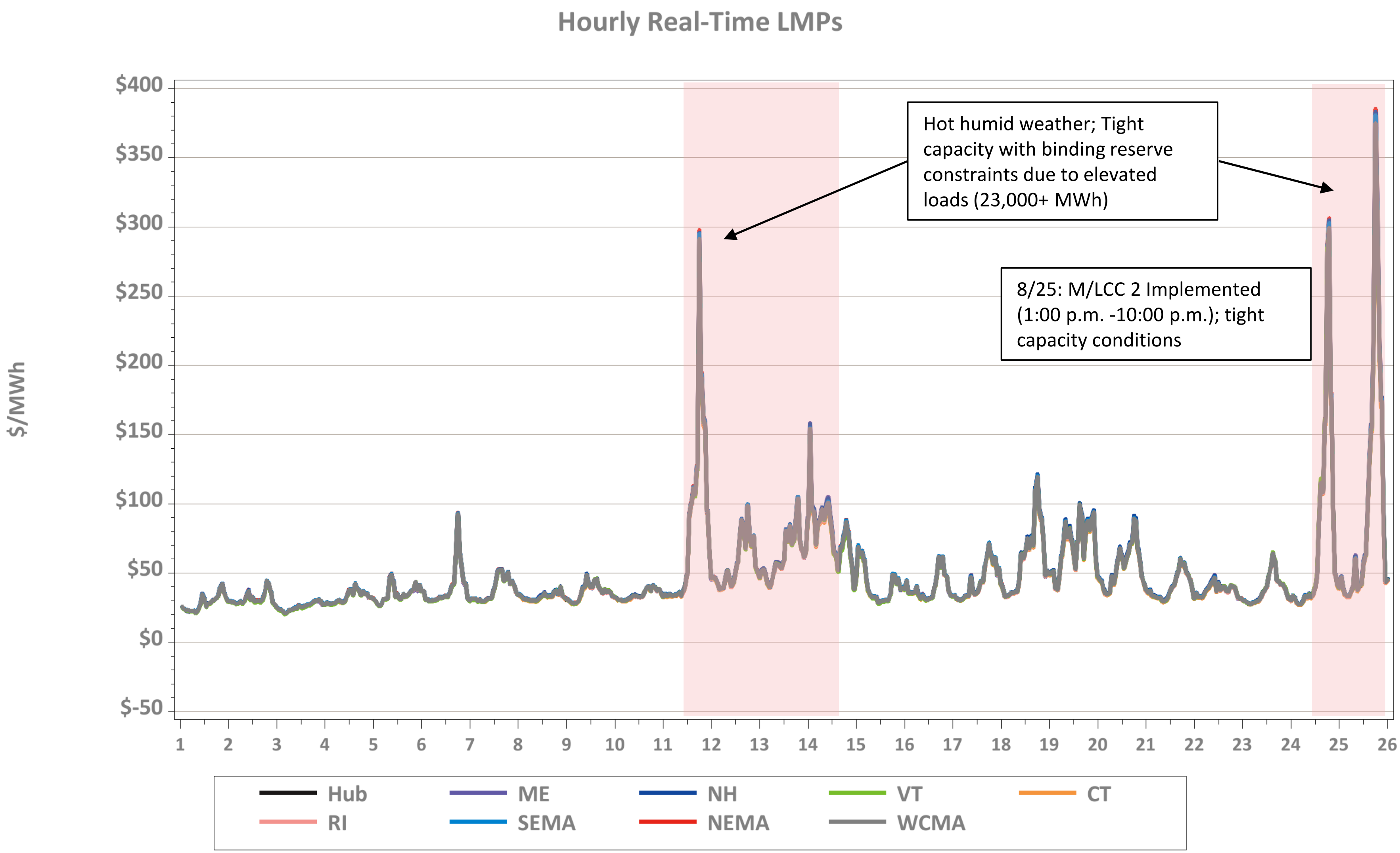
ice Global markets in clear view

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

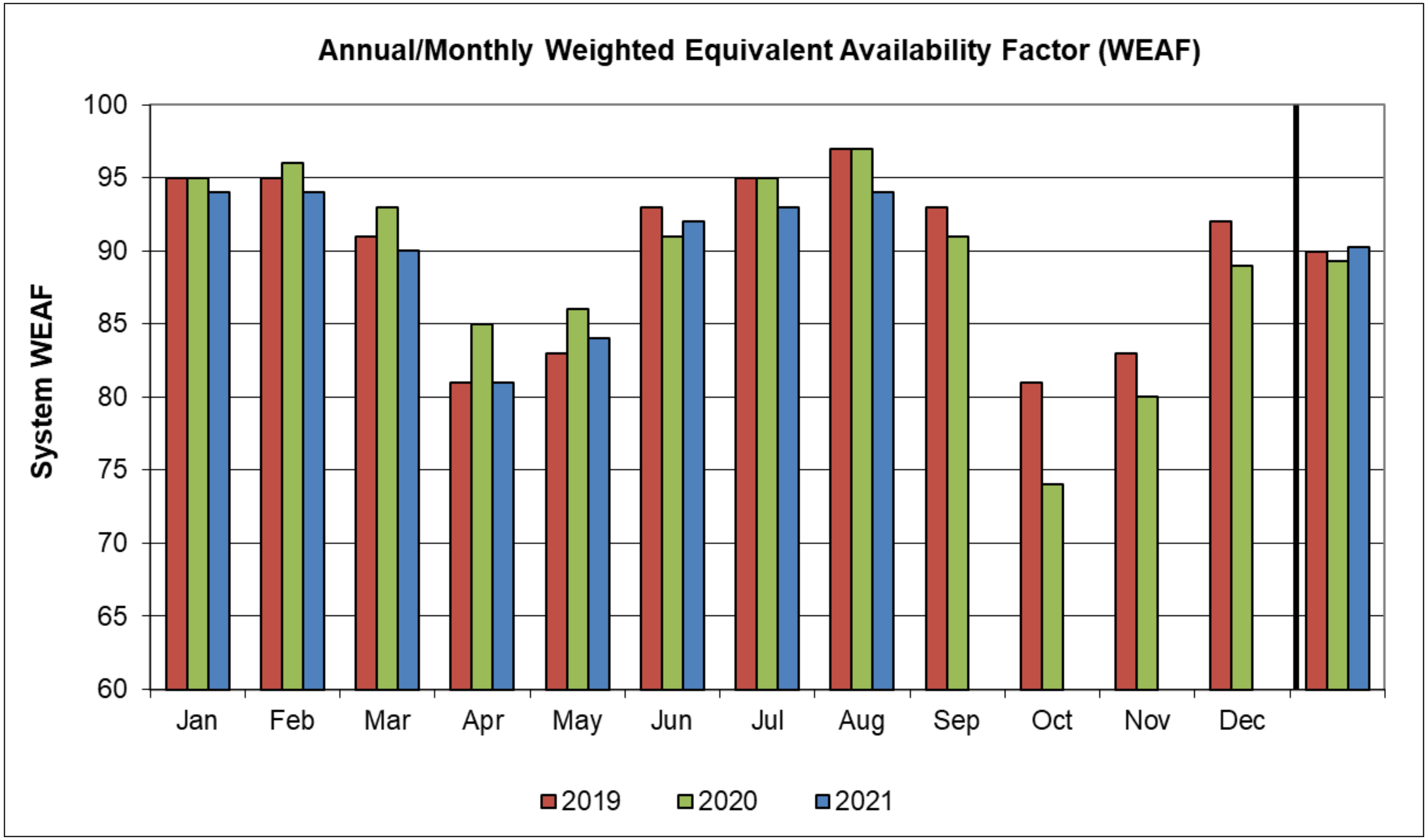
Hourly DA LMPs, August 1-25, 2021



Hourly RT LMPs, August 1-25, 2021



System Unit Availability



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

Data as of 8/25/2021

BACK-UP DETAIL

DEMAND RESPONSE

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

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	85.4	202.5	0.0	287.9
NH	40.5	145.7	0.0	186.2
VT	37.6	125.6	0.0	163.2
CT	137.3	132.6	614.8	884.7
RI	39.3	323.4	0.0	362.7
SEMA	45.3	507.0	0.0	552.3
WCMA	85.0	538.6	39.6	663.2
NEMA	60.3	858.6	0.0	918.9
Total	**530.7**	**2,834.0**	**654.4**	**4,019.1**

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

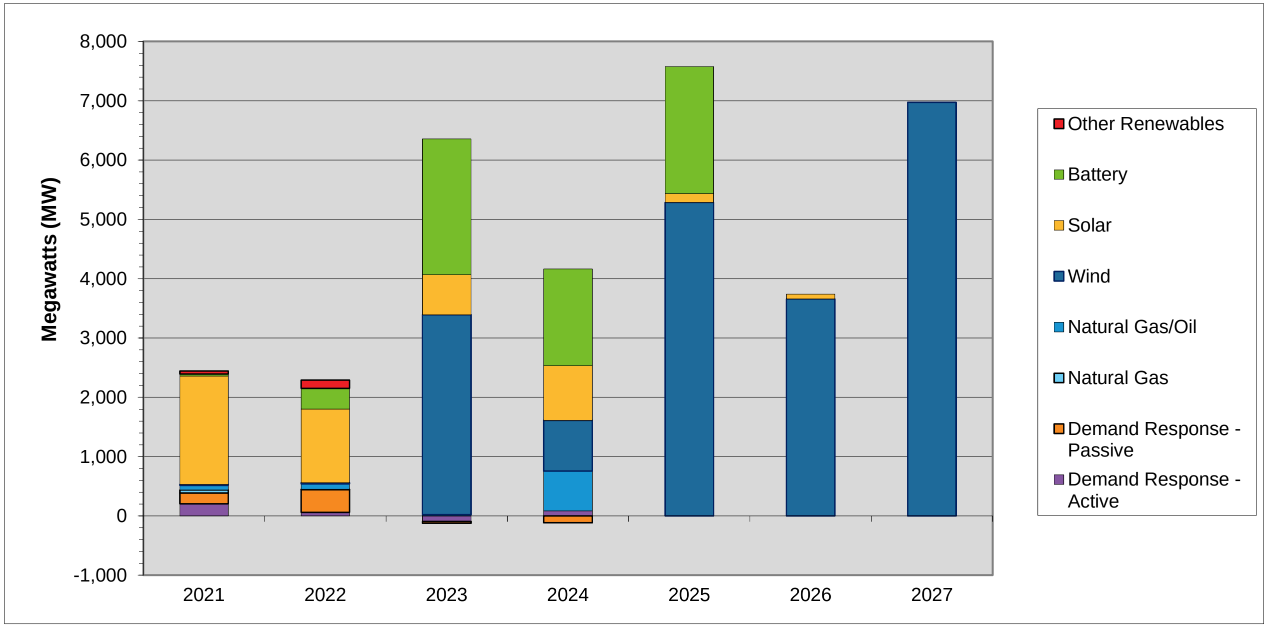
NEW GENERATION

New Generation Update
Based on Queue as of 8/27/21

- Seven new projects totaling 951 MW applied for interconnection study since the last update
  - They consist of one battery, two offshore wind, two solar projects and two solar with battery projects with in-service dates ranging from 2021 to 2021
- One project went commercial and two projects were withdrawn
- In total, 296 generation projects are currently being tracked by the ISO, totaling approximately 32,631 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



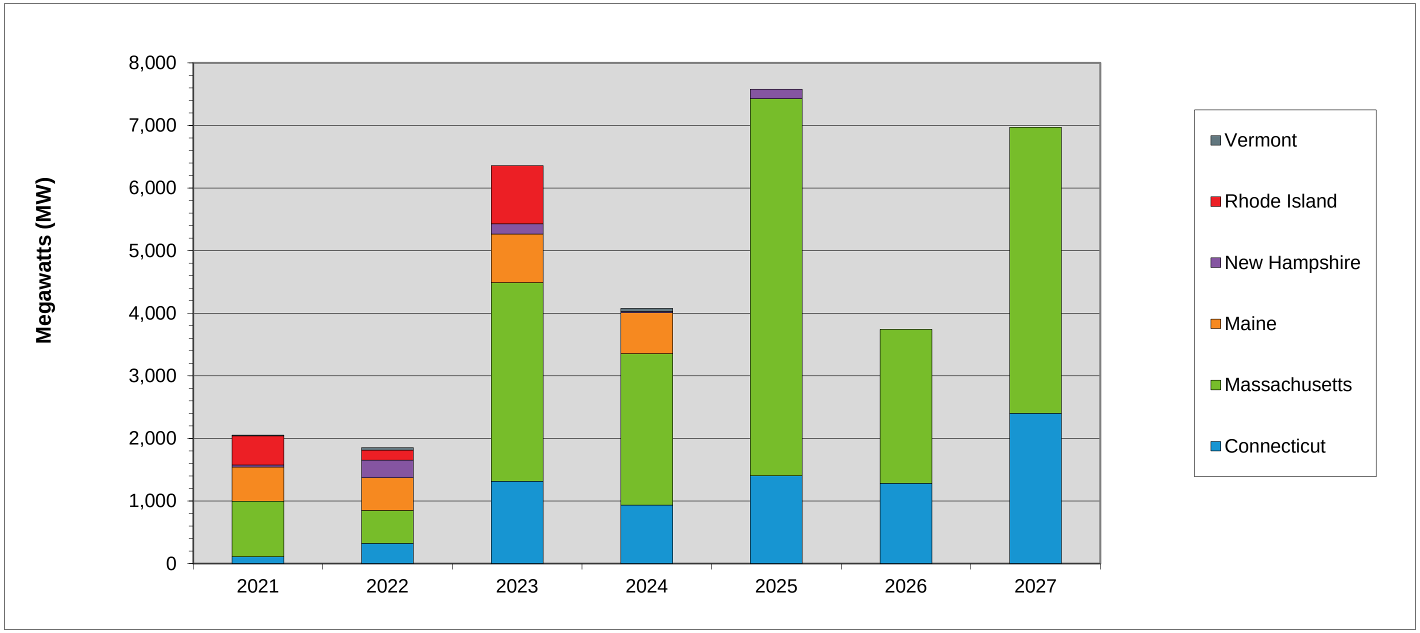
	2021	2022	2023	2024	2025	2026	2027	Total MW	% of Total[1]
Other Renewables	48	142	0	0	0	0	0	190	0.6
Battery	34	347	2,294	1,630	2,140	0	0	6,445	19.3
Solar[2]	1,828	1,242	675	923	150	83	0	4,901	14.7
Wind	19	20	3,367	852	5,287	3,658	6,972	20,175	60.6
Natural Gas/Oil[3]	76	89	23	672	0	0	0	860	2.6
Natural Gas	49	11	0	0	0	0	0	60	0.2
Demand Response - Passive	184	380	-28	-114	0	0	0	422	1.3
Demand Response - Active	204	62	-94	86	0	0	0	258	0.8
Totals	**2,442**	**2,293**	**6,237**	**4,049**	**7,577**	**3,741**	**6,972**	**33,311**	**100.0**

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

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

Actual and Projected Annual Generator Capacity Additions

By State



	2021	2022	2023	2024	2025	2026	2027	Total MW	% of Total[1]
Vermont	15	40	0	50	0	0	0	105	0.3
Rhode Island	466	160	931	0	0	0	0	1,557	4.8
New Hampshire	30	281	164	20	150	0	0	645	2.0
Maine	546	523	774	652	0	0	0	2,495	7.6
Massachusetts	888	523	3,178	2,421	6,022	2,458	4,572	20,062	61.5
Connecticut	109	324	1,312	934	1,405	1,283	2,400	7,767	23.8
Totals	**2,054**	**1,851**	**6,359**	**4,077**	**7,577**	**3,741**	**6,972**	**32,631**	**100.0**

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

New Generation Projection

By Fuel Type

Unit Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	0	0	0	0	0	0
Battery Storage	36	6,445	0	0	36	6,445
Fuel Cell	4	54	1	10	3	44
Hydro	3	99	2	71	1	28
Natural Gas	6	60	0	0	6	60
Natural Gas/Oil	7	860	1	14	6	846
Nuclear	1	37	0	0	1	37
Solar	209	4,901	20	336	189	4,565
Wind	30	20,175	1	15	29	20,160
Total	296	32,631	25	446	271	32,185

- 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	7	124	2	15	5	109
Intermediate	8	818	1	14	7	804
Peaker	251	11,514	21	402	230	11,112
Wind Turbine	30	20,175	1	15	29	20,160
Total	296	32,631	25	446	271	32,185

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

New Generation Projection

By Operating Type and Fuel Type

Unit Type	Total		Baseload		Intermediate		Peaker		Wind Turbine	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	0	0	0	0	0	0	0	0	0	0
Battery Storage	36	6,445	0	0	0	0	36	6,445	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	6	60	0	0	3	43	3	17	0	0
Natural Gas/Oil	7	860	0	0	5	775	2	85	0	0
Nuclear	1	37	1	37	0	0	0	0	0	0
Solar	209	4,901	0	0	0	0	209	4,901	0	0
Wind	30	20,175	0	0	0	0	0	0	30	20,175
Total	296	32,631	7	124	8	818	251	11,514	30	20,175

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

FORWARD CAPACITY MARKET

Capacity Supply Obligation (CSO) FCA 12

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	624.445	659.137	34.692	603.776	-55.361	587.270	-16.506
	Passive Demand	2,975.36	3,045.073	69.713	3,123.232	78.159	3,322.722	199.490
Demand Total		**3,599.81**	**3,704.21**	**104.4**	**3,727.008**	**22.798**	**3,909.992**	**182.984**
Generator	*Non-Intermittent*	29,130.75	29,244.404	113.654	28,620.245	-624.159	28,941.276	321.031
	Intermittent	880.317	806.609	-73.708	660.932	-145.677	663.179	2.247
Generator Total		**30,011.07**	**30,051.013**	**39.943**	**29,281.177**	**-769.836**	**29,604.455**	**323.278**
Import Total		**1,217**	**1,305.487**	**88.487**	**1,307.587**	**2.10**	**1207.78**	**-99.807**
Grand Total*		**34,827.88**	**35,060.710**	**232.83**	**34,315.772**	**-744.94**	**34,722.227**	**406.455**
Net ICR (NICR)		**33,725**	**33,550**	**-175**	**32,230**	**-1,320**	**32,925**	**695**

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

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

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

Capacity Supply Obligation FCA 13

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	685.554	683.116	-2.438				
	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	688.07	96.027				
	Passive Demand	3,327.071	3,327.932	0.861				
Demand Total		**3,919.114**	**4,016.002**	**96.888**				
Generator	*Non-Intermittent*	27,816.902	28,275.143	458.241				
	Intermittent	1,160.916	1,128.446	-32.47				
Generator Total		**28,977.818**	**29,403.589**	**425.771**				
Import Total		**1,058.72**	**1,058.72**	**0**				
Grand Total*		**33,955.652**	**34,478.311**	**522.661**				
Net ICR (NICR)		**32,490**	**32,980**	**490**				

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

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

Capacity Supply Obligation FCA 15

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

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

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

Active/Passive Demand Response

CSO Totals by Commitment Period

Commitment Period	Active/Passive	Existing	New	Grand Total
2019-20	Active	357.221	20.304	377.525
	Passive	2,018.20	350.43	2,368.63
	Grand Total	**2375.422**	**370.734**	**2746.156**
2020-21	Active	334.634	85.294	419.928
	Passive	2,236.73	554.292	2,791.02
	Grand Total	**2571.361**	**639.586**	**3210.947**
2021-22	Active	480.941	143.504	624.445
	Passive	2,604.79	370.568	2,975.36
	Grand Total	**3085.734**	**514.072**	**3599.806**
2022-23	Active	598.376	87.178	685.554
	Passive	2,788.33	566.363	3,354.69
	Grand Total	**3386.703**	**653.541**	**4040.244**
2023-24	Active	560.55	31.493	592.043
	Passive	3,035.51	291.565	3,327.07
	Grand Total	**3596.056**	**323.058**	**3919.114**
2024-25	Active	674.153	3.520	677.673
	Passive	3,046.064	166.801	3,212.865
	Grand Total	**3,720.217**	**170.321**	**3,890.538**

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

What are Daily NCPC Payments?

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

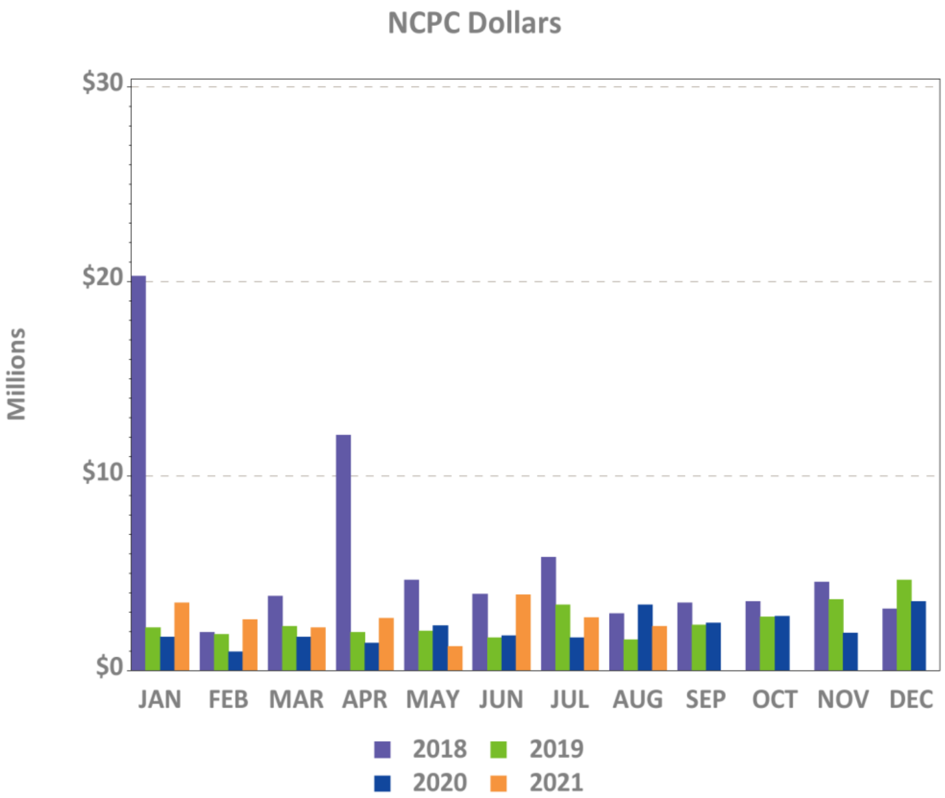
Definitions

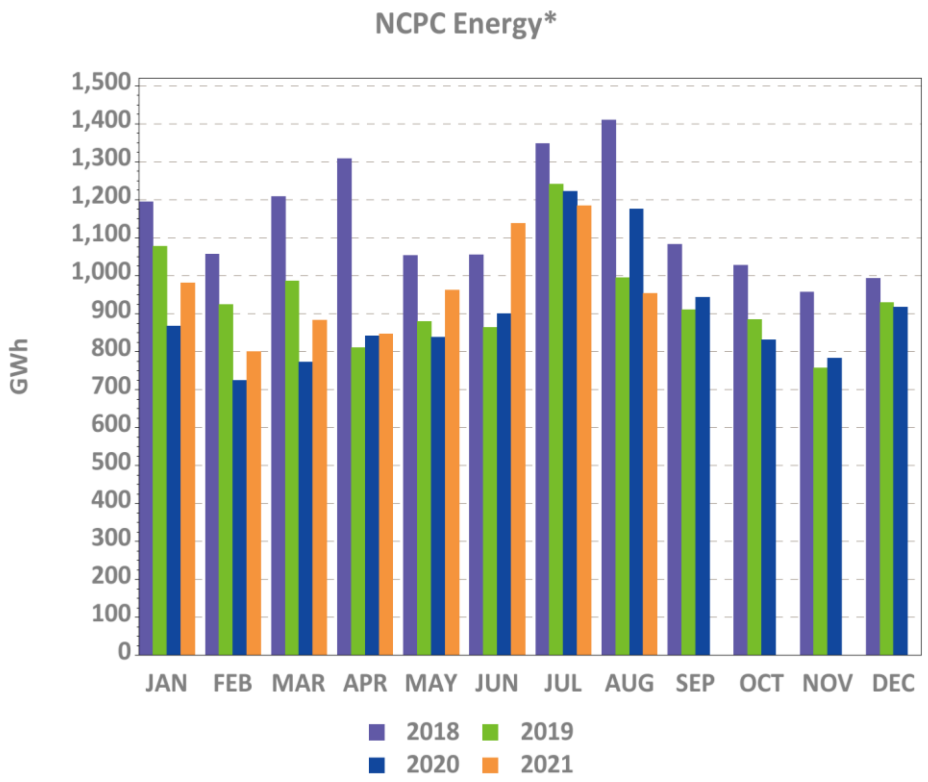
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing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

Charge Allocation Key

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

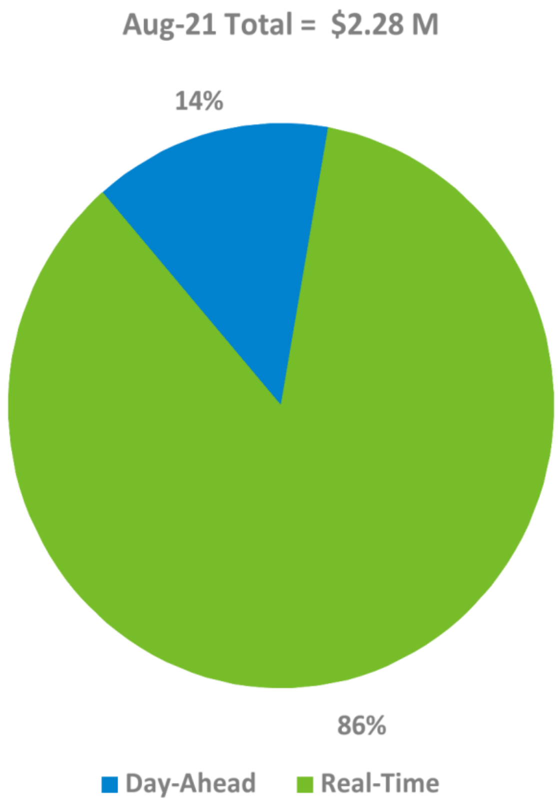
Year-Over-Year Total NCPC Dollars and Energy

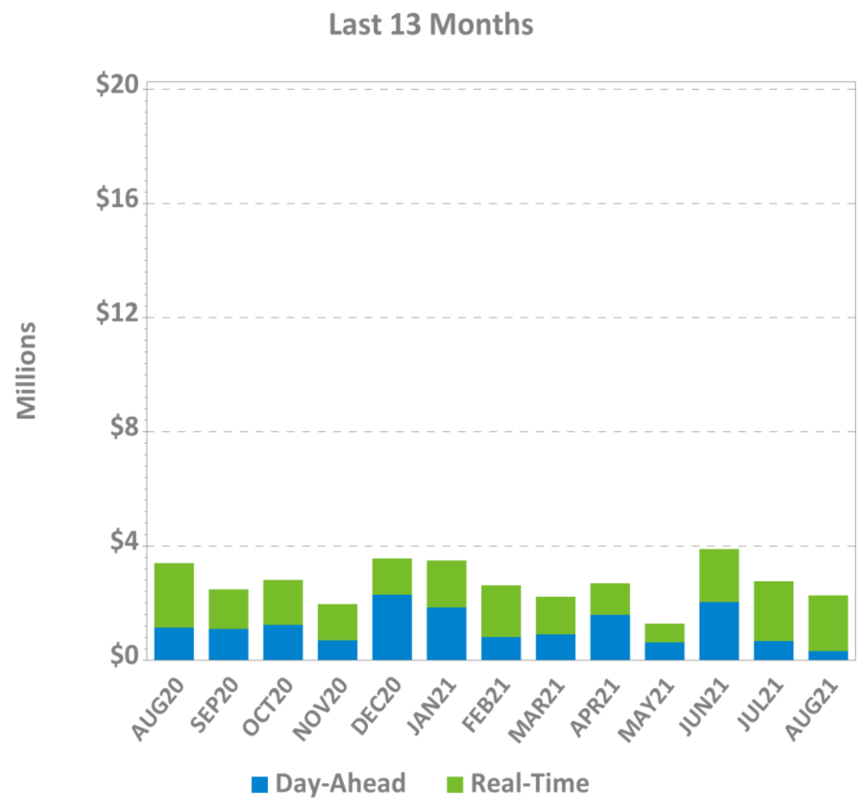




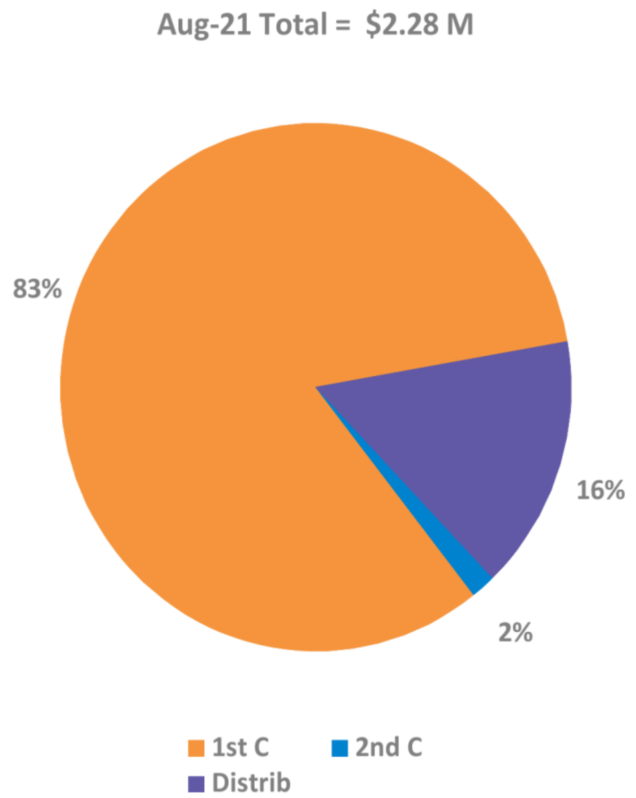
* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

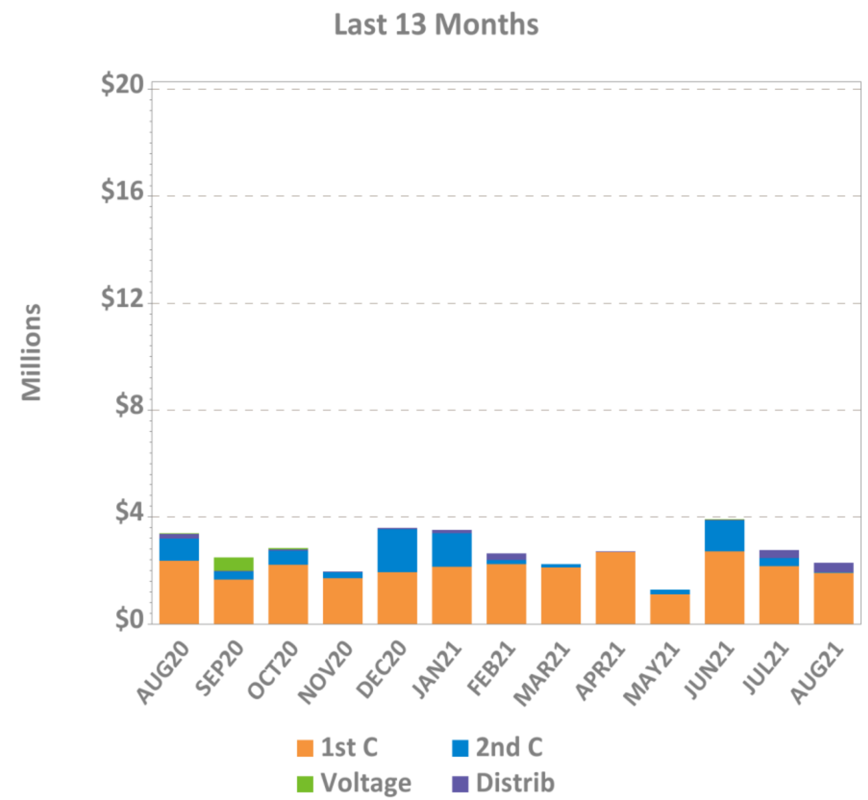
DA and RT NCPC Charges





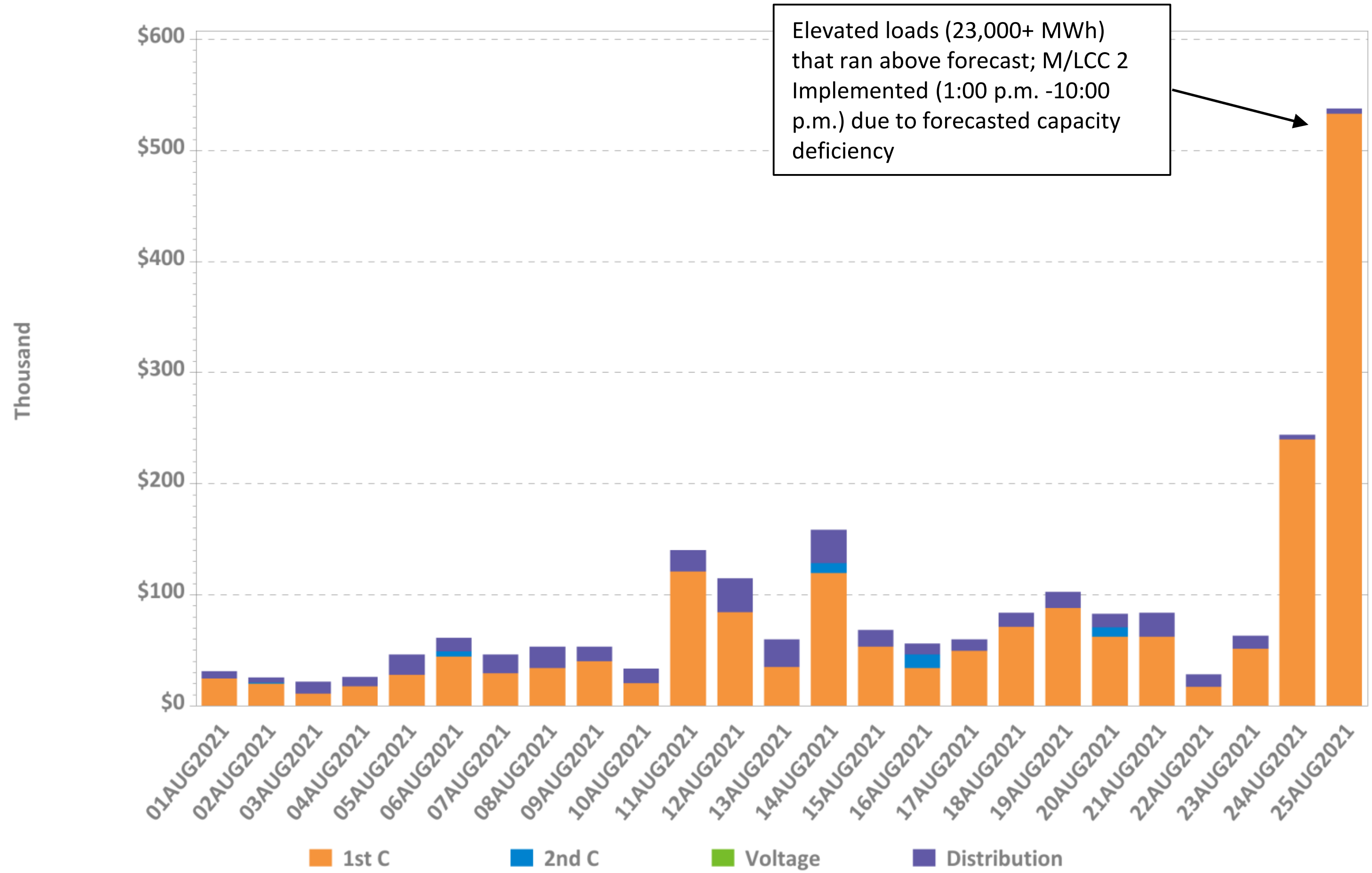
NCPC Charges by Type



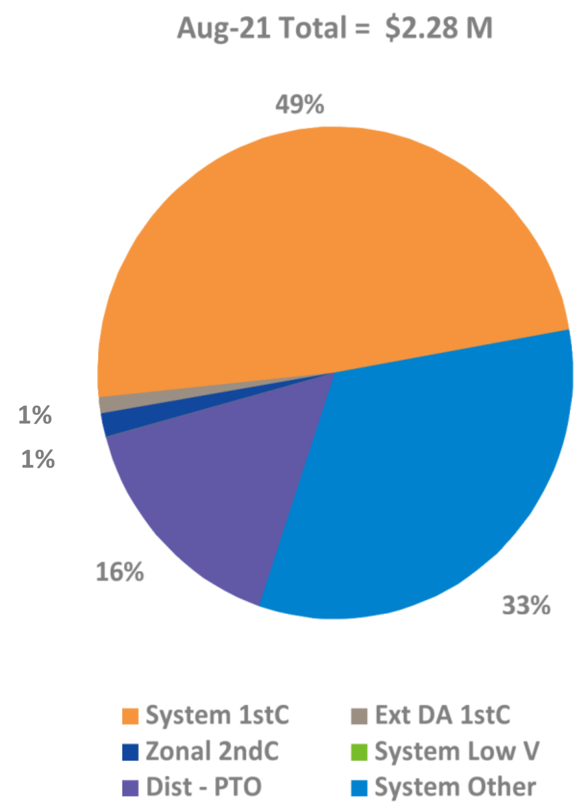


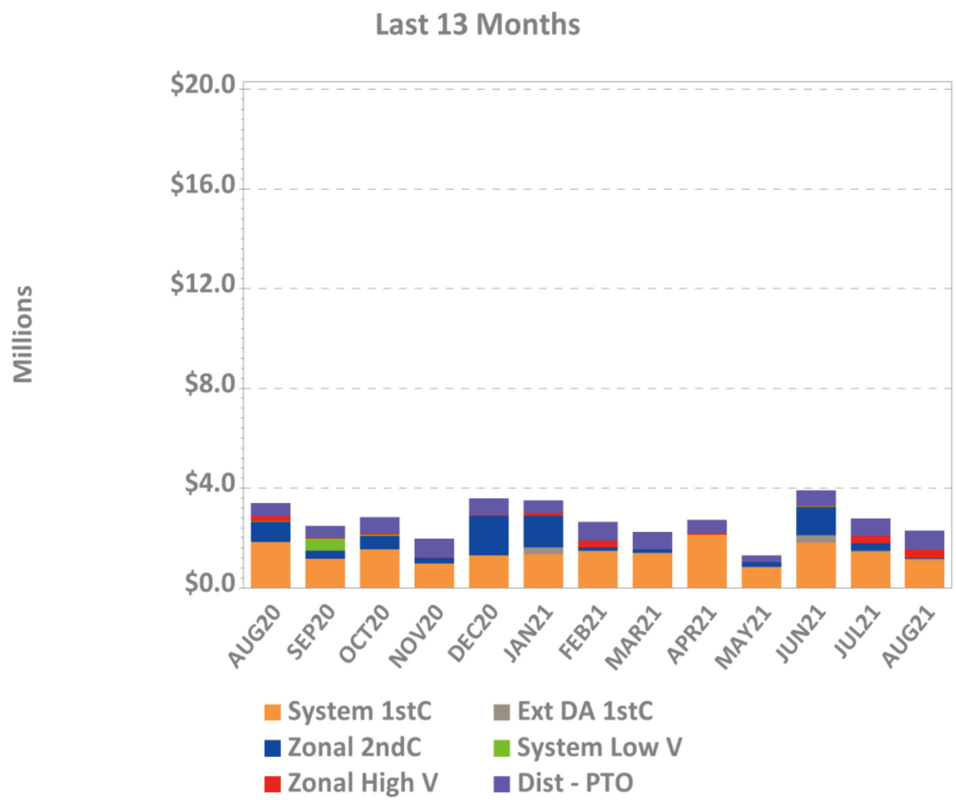
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



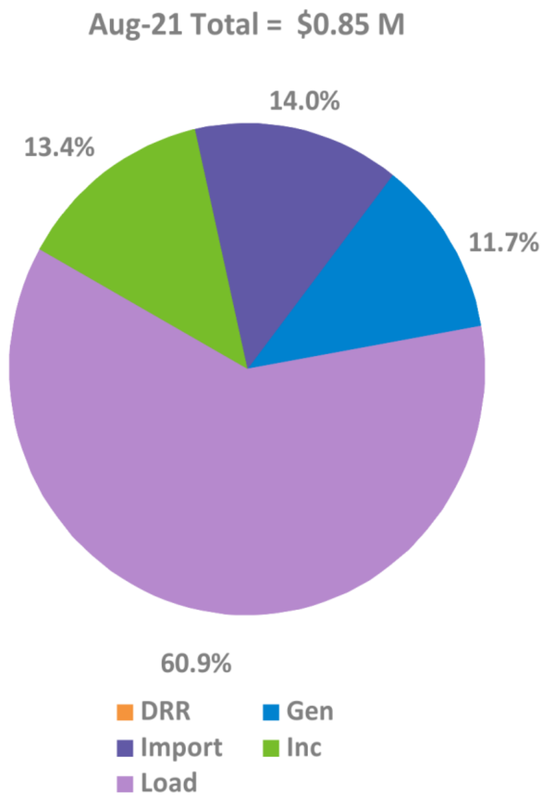
NCPC Charges by Allocation

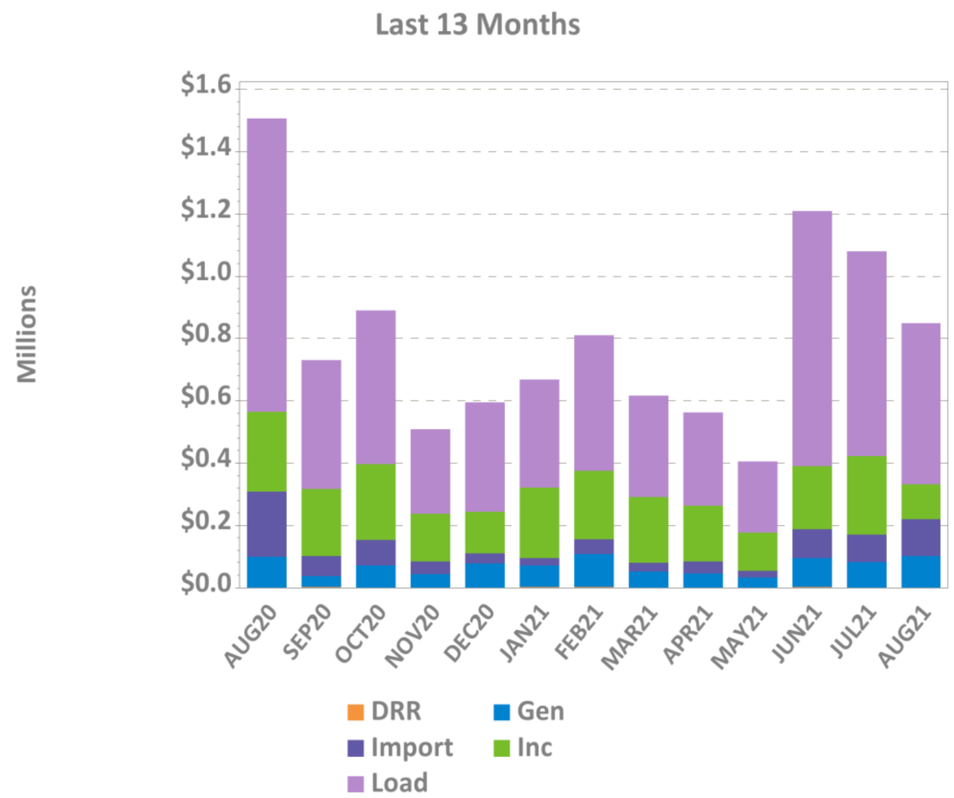




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

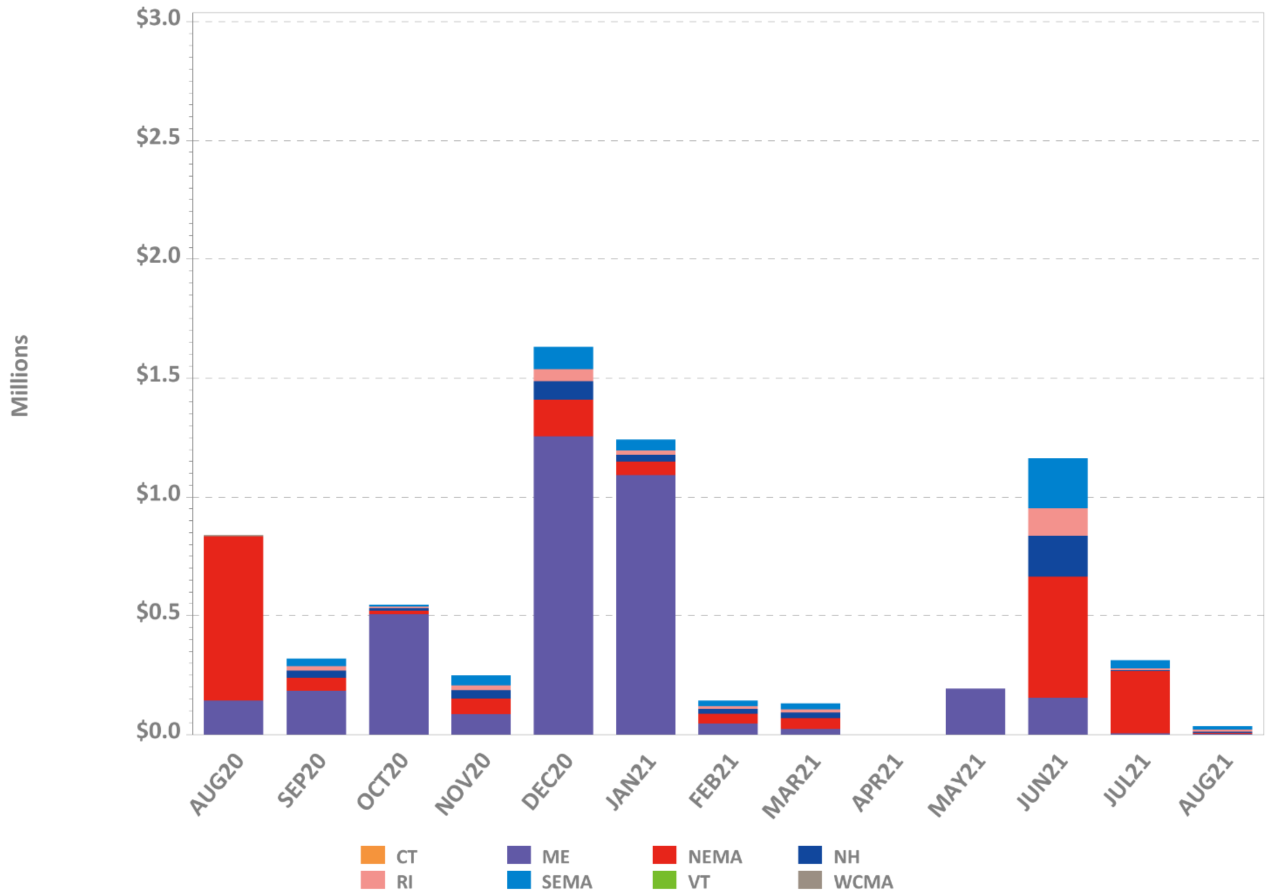
RT First Contingency Charges by Deviation Type





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

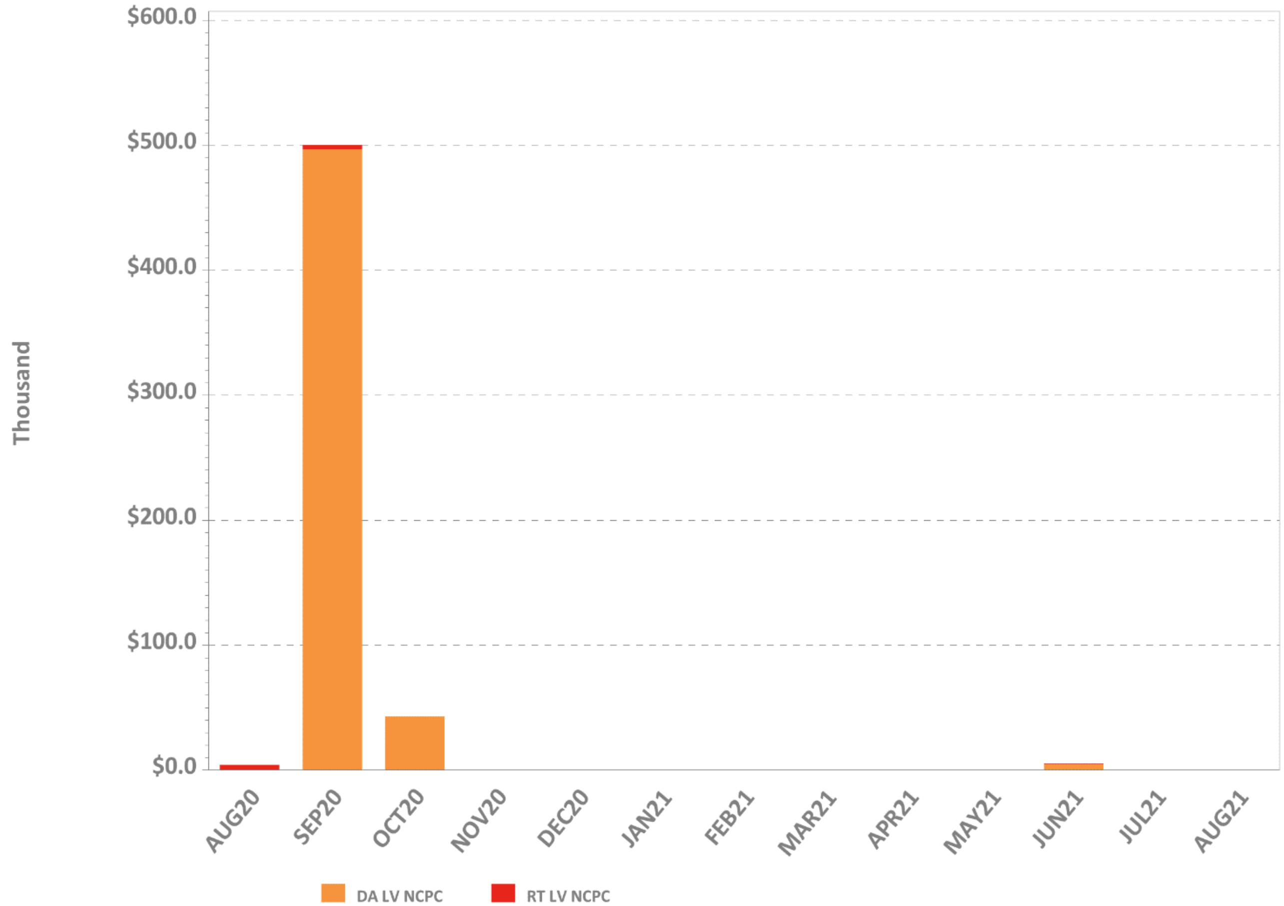
LSCPR Charges by Reliability Region



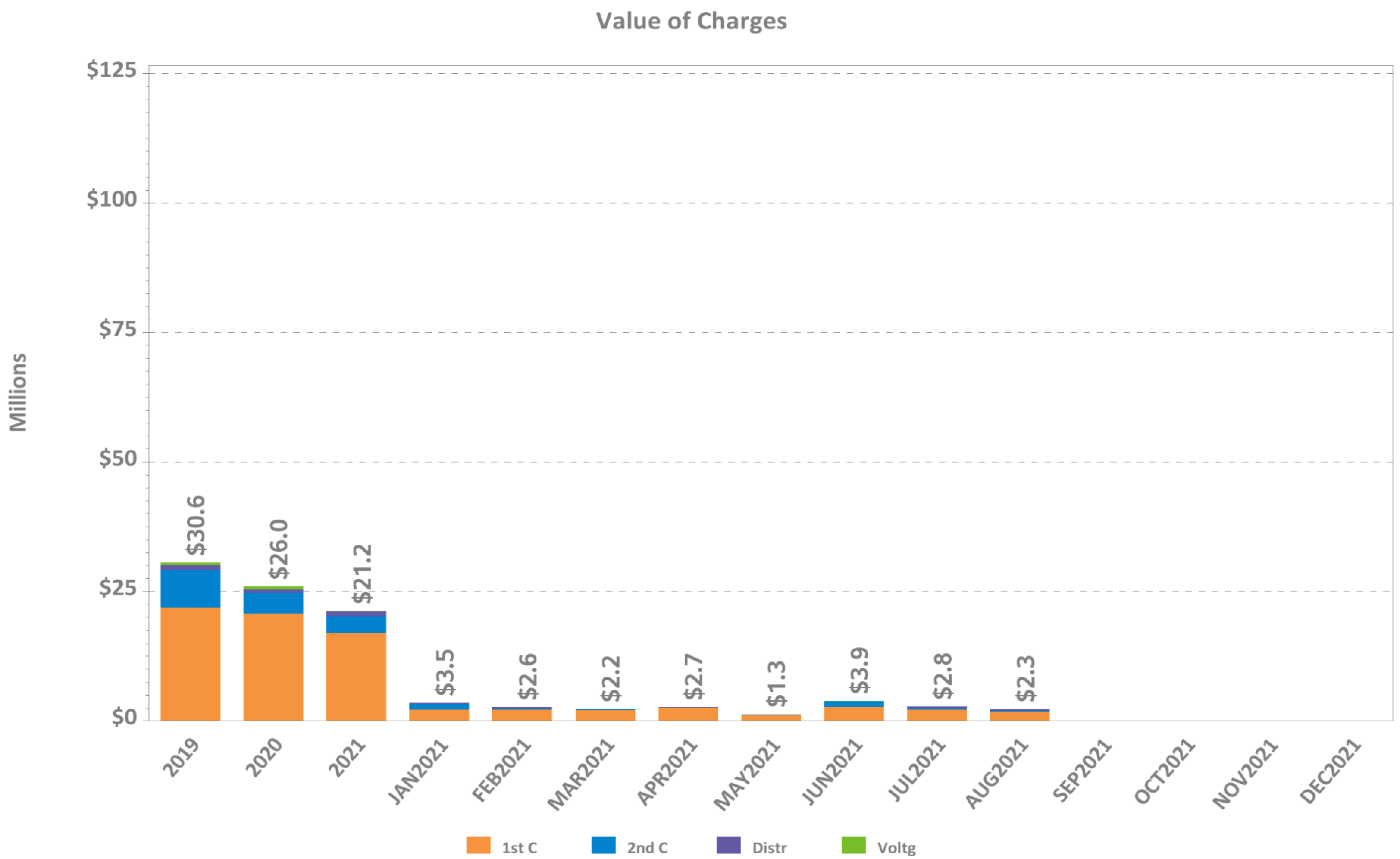
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

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

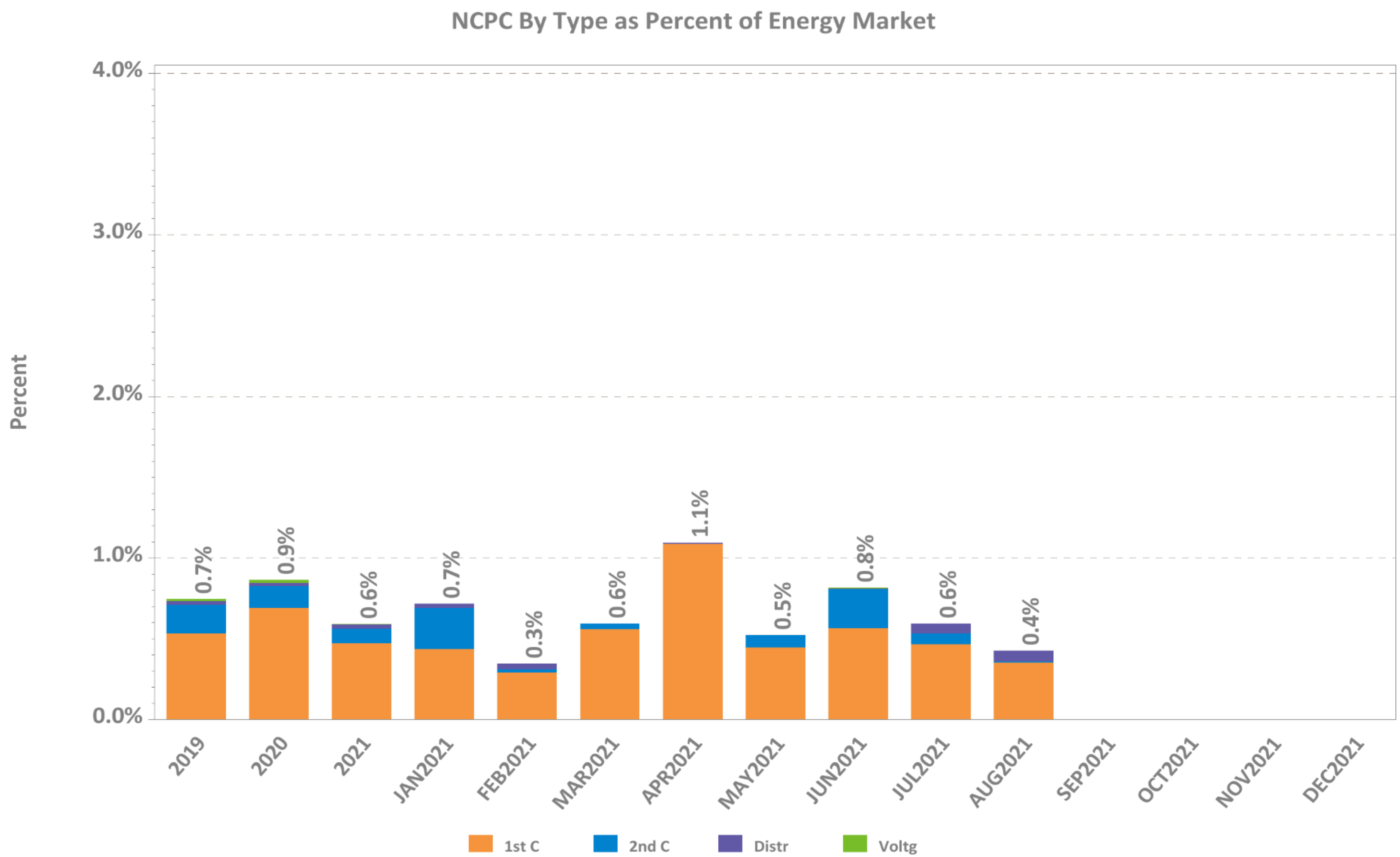
NCPC Charges for Voltage Support and High Voltage Control



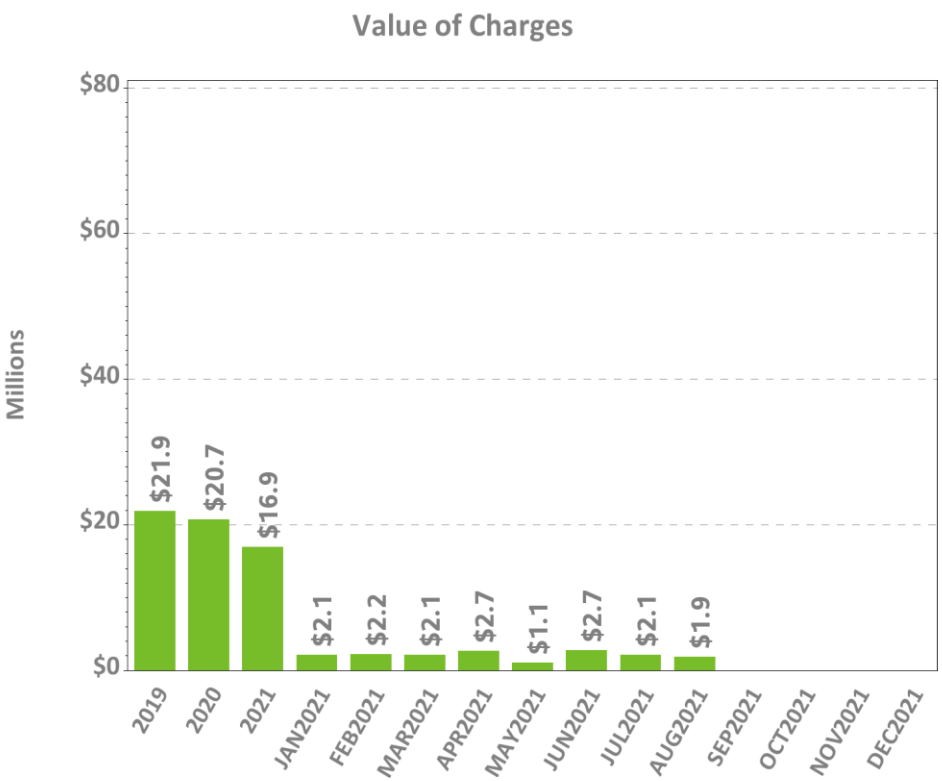
NCPC Charges by Type

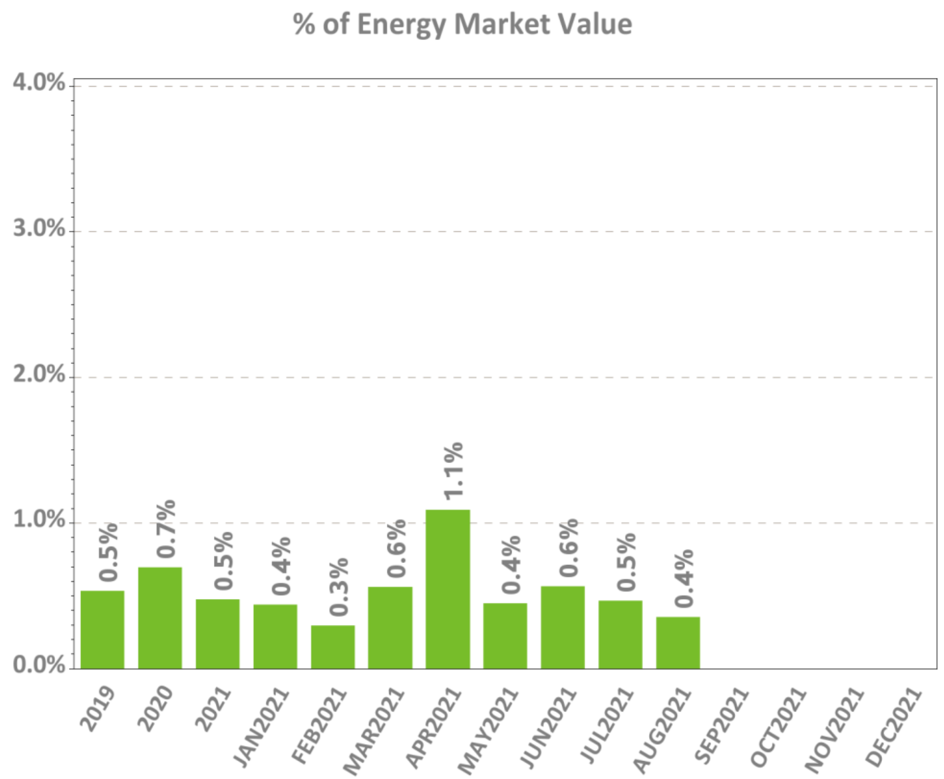


NCPC Charges as Percent of Energy Market



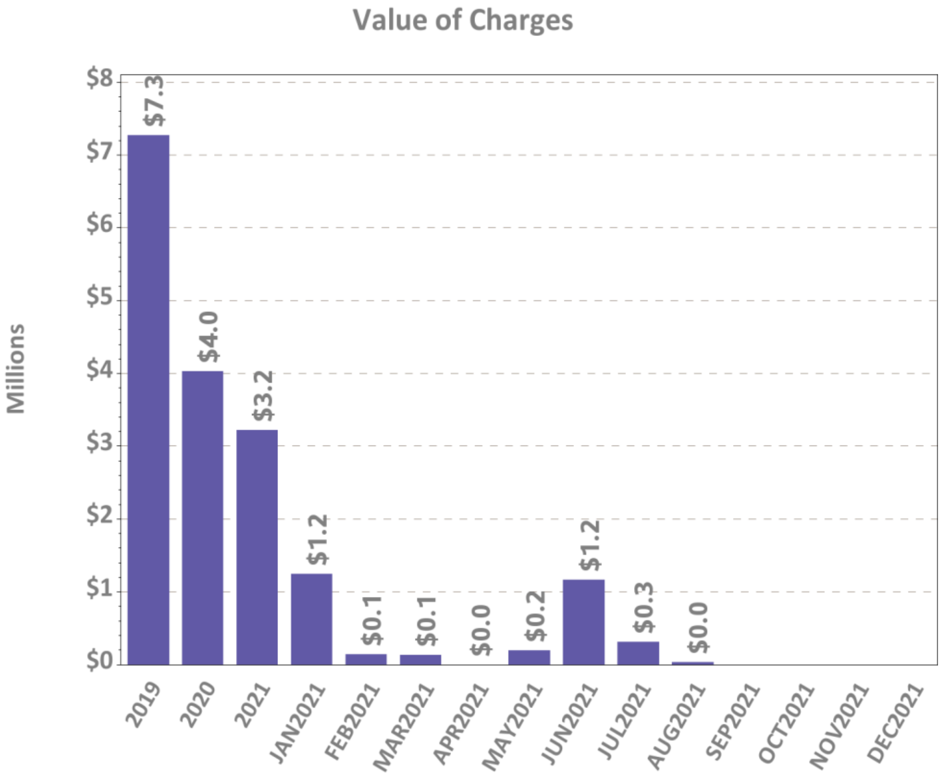
First Contingency NCPC Charges

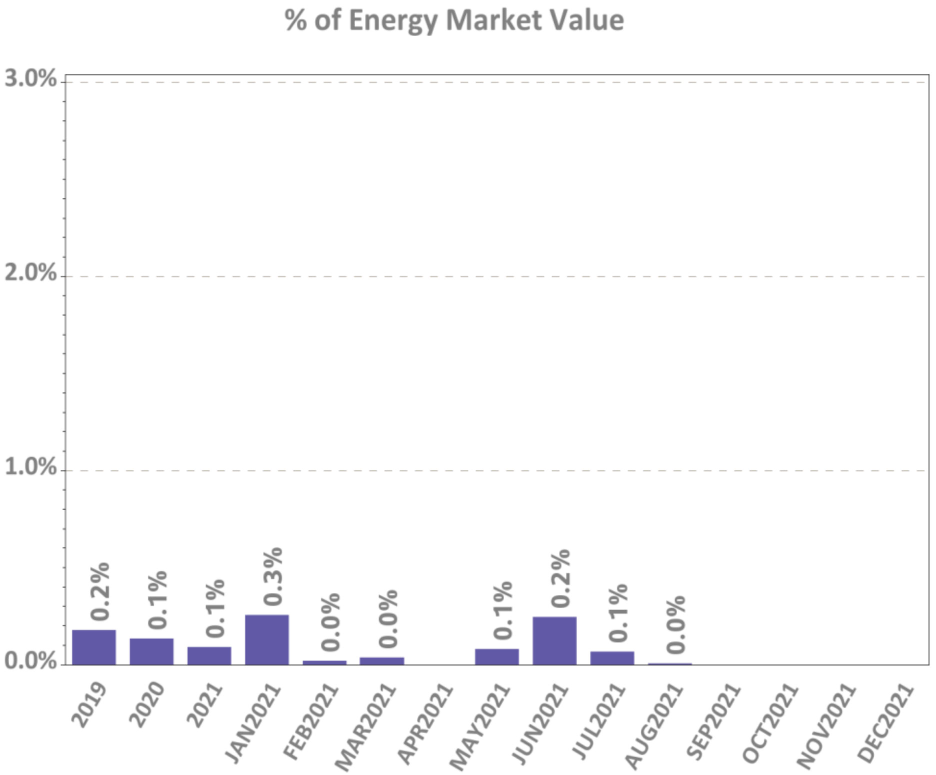




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

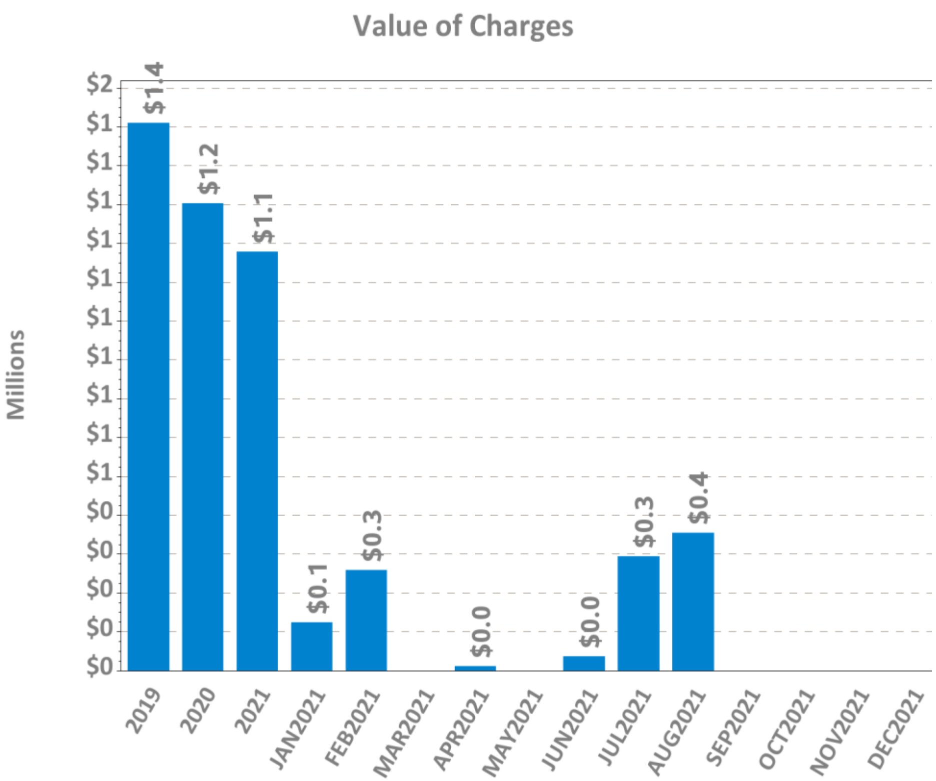
Second Contingency NCPC Charges

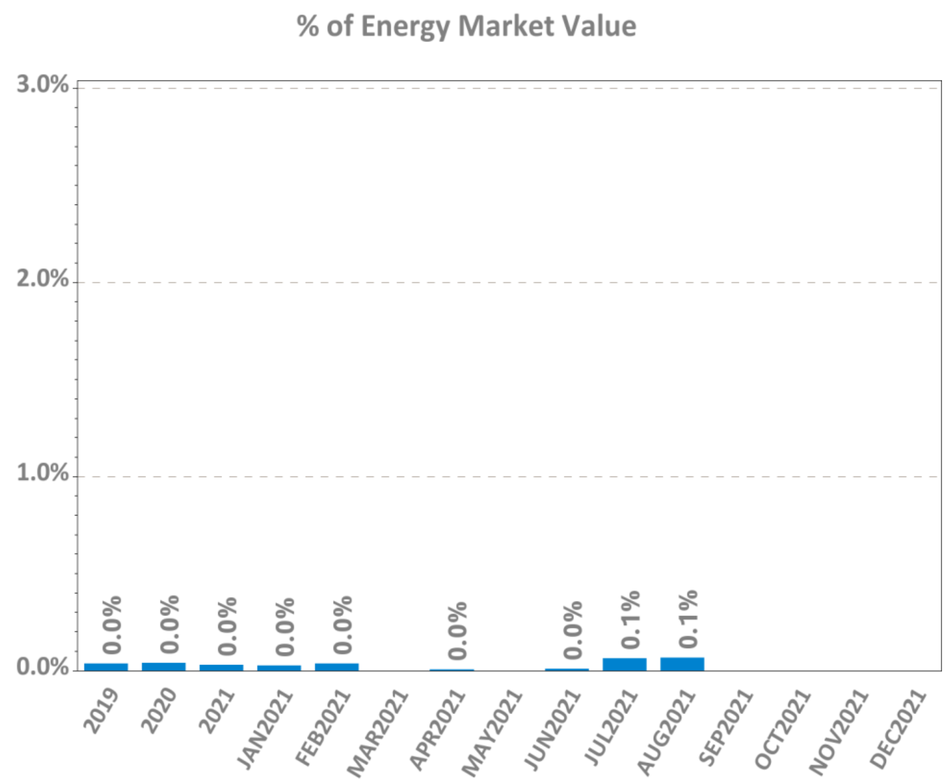




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

Voltage and Distribution NCPC Charges





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

DA vs. RT Pricing

The following slides outline:

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

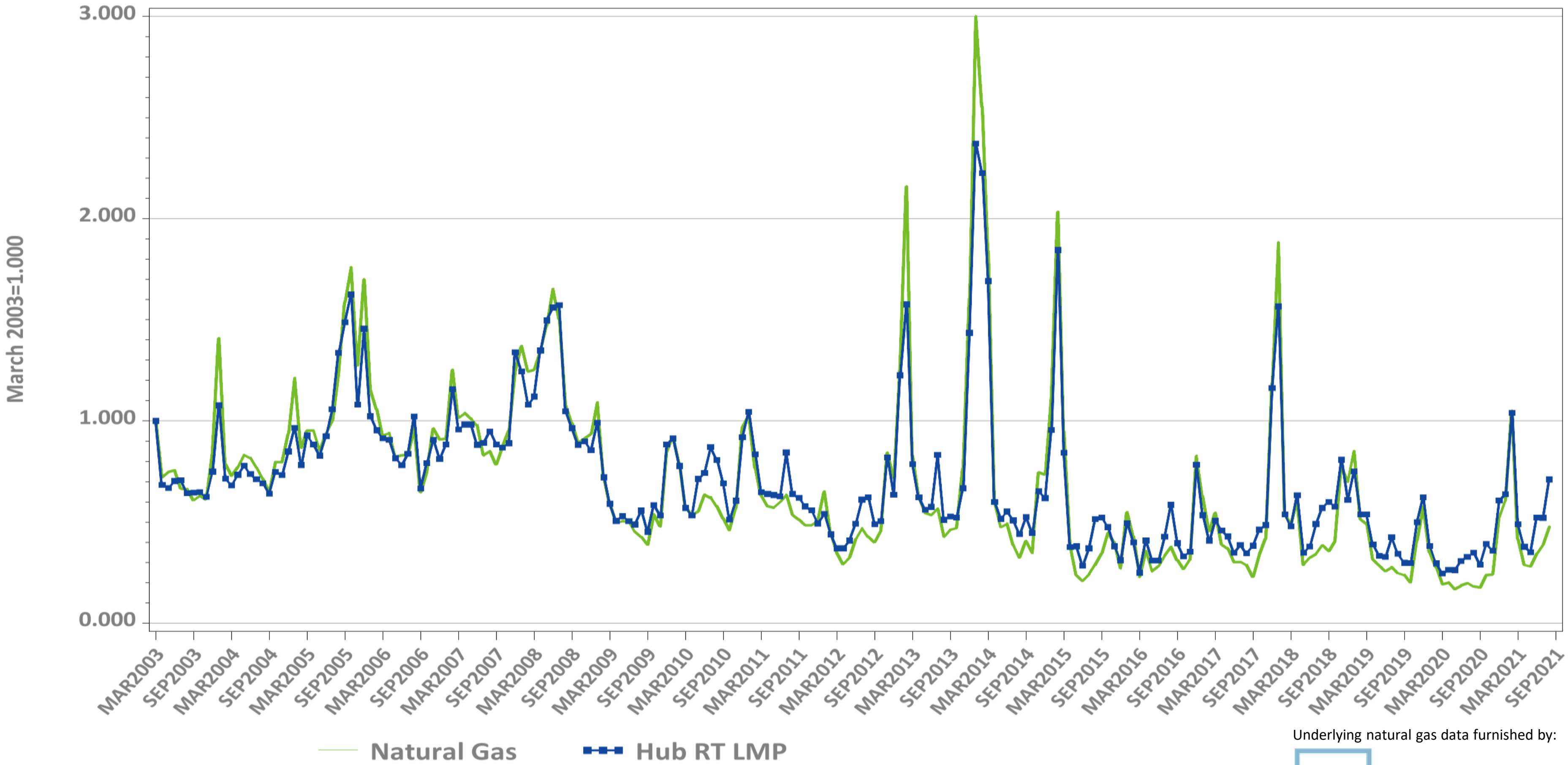
DA vs. RT LMPs ($/MWh)

Arithmetic Average

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

August-20	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$24.25	$23.12	$24.12	$24.18	$23.60	$23.61	$23.91	$23.83	$23.79
Real-Time	$24.30	$23.44	$24.23	$24.32	$23.77	$23.71	$23.98	$23.91	$23.87
RT Delta %	0.2%	1.3%	0.4%	0.6%	0.7%	0.4%	0.3%	0.4%	0.4%
August-21	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Day-Ahead	$48.87	$47.30	$48.33	$48.88	$48.12	$48.03	$48.64	$48.34	$48.30
Real-Time	$49.53	$48.11	$49.06	$49.51	$48.61	$48.53	$49.21	$48.88	$48.83
RT Delta %	1.3%	1.7%	1.5%	1.3%	1.0%	1.0%	1.2%	1.1%	1.1%
Annual Diff.	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Yr over Yr DA	101.5%	104.6%	100.4%	102.1%	103.9%	103.4%	103.5%	102.9%	103.0%
Yr over Yr RT	103.8%	105.3%	102.5%	103.6%	104.5%	104.7%	105.2%	104.4%	104.5%

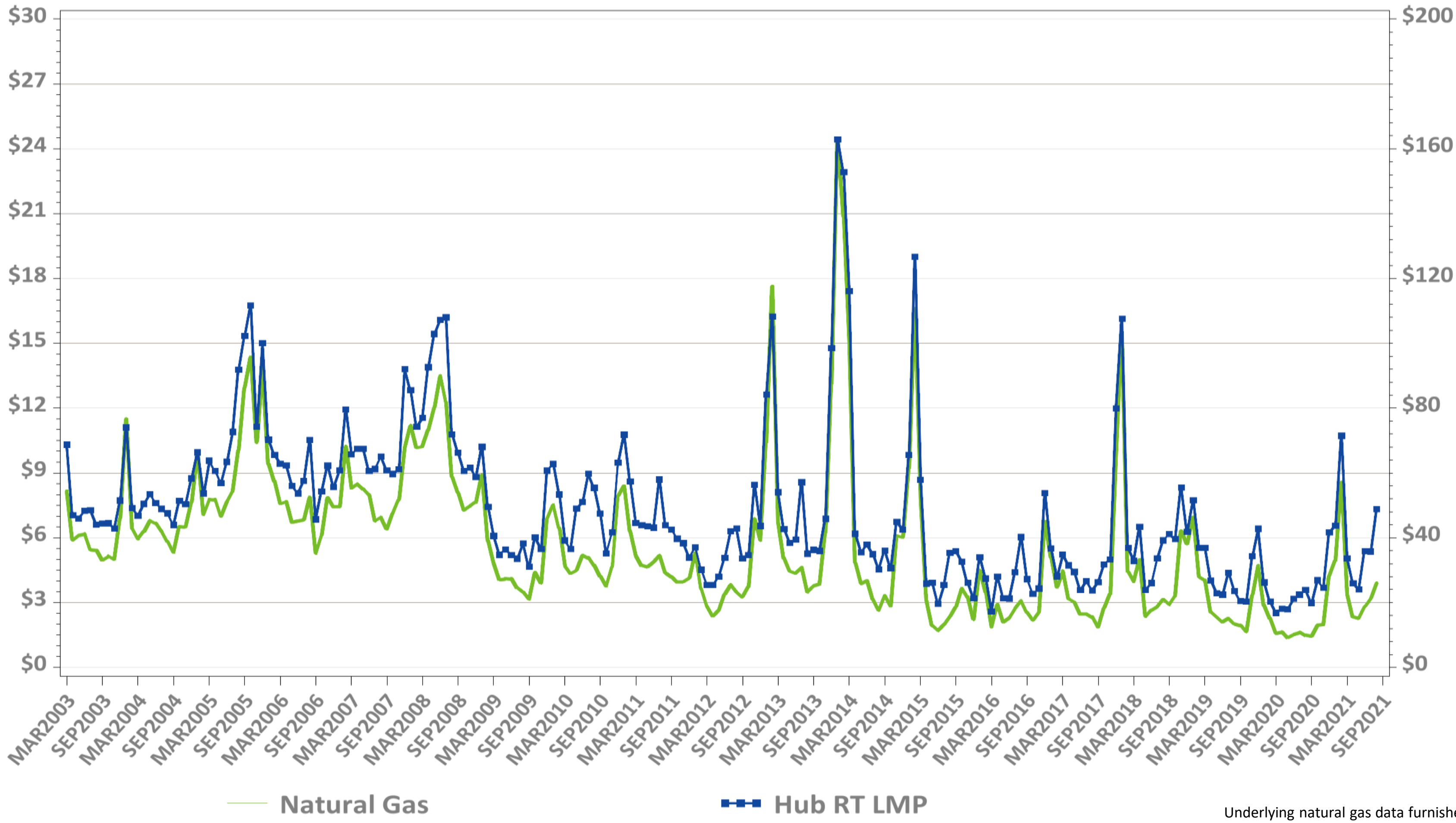
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

ICE Global markets in clear view

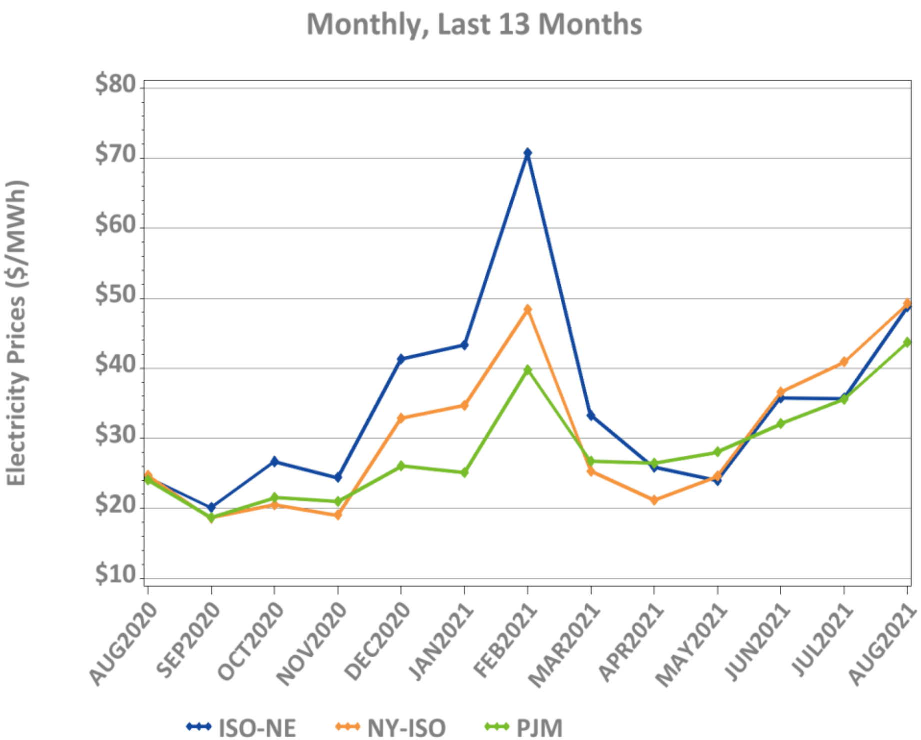
Monthly Average Fuel Price and RT Hub LMP



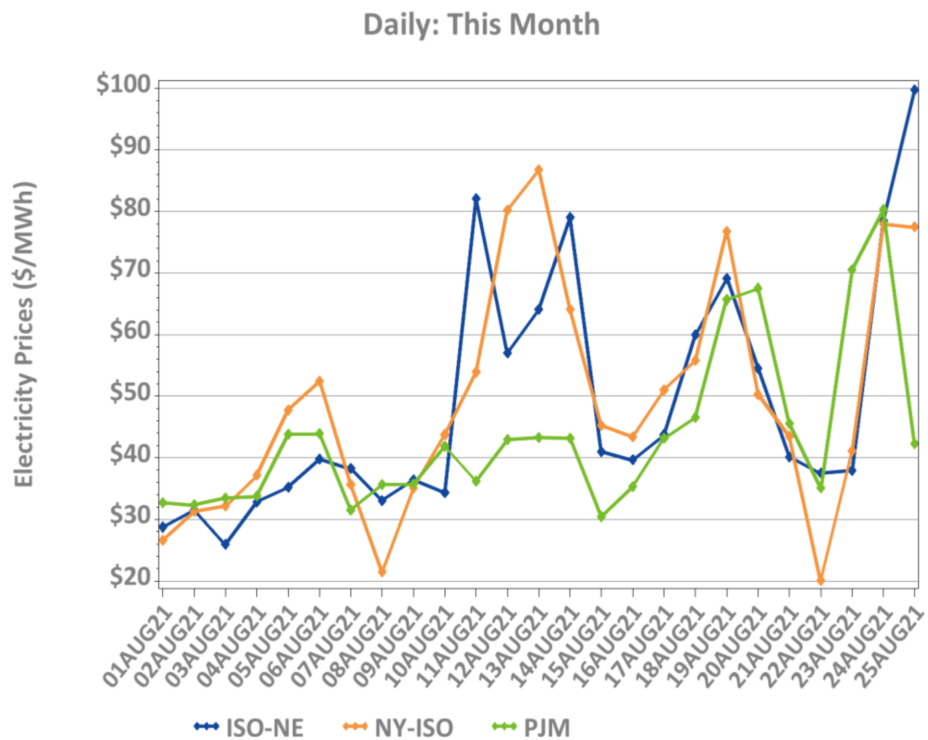
Underlying natural gas data furnished by:

ice Global markets in clear view

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

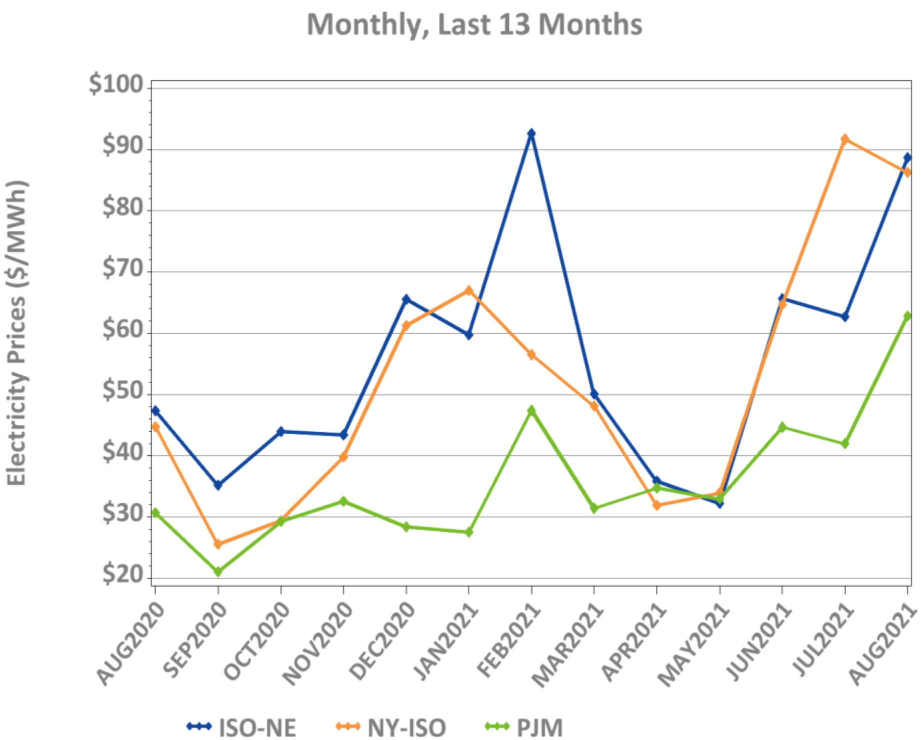


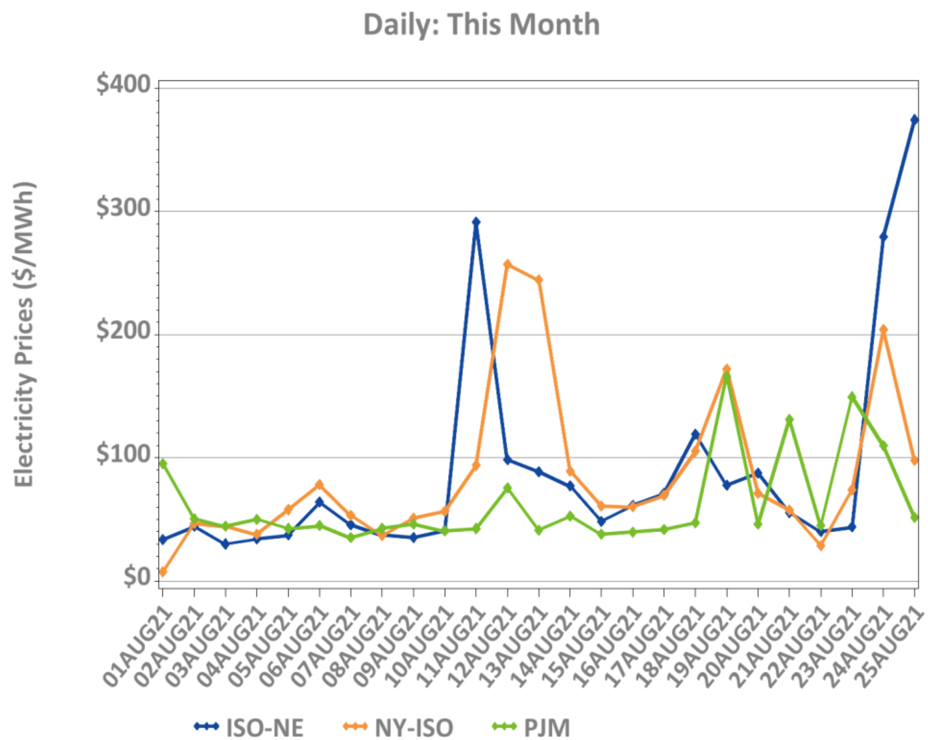
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

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





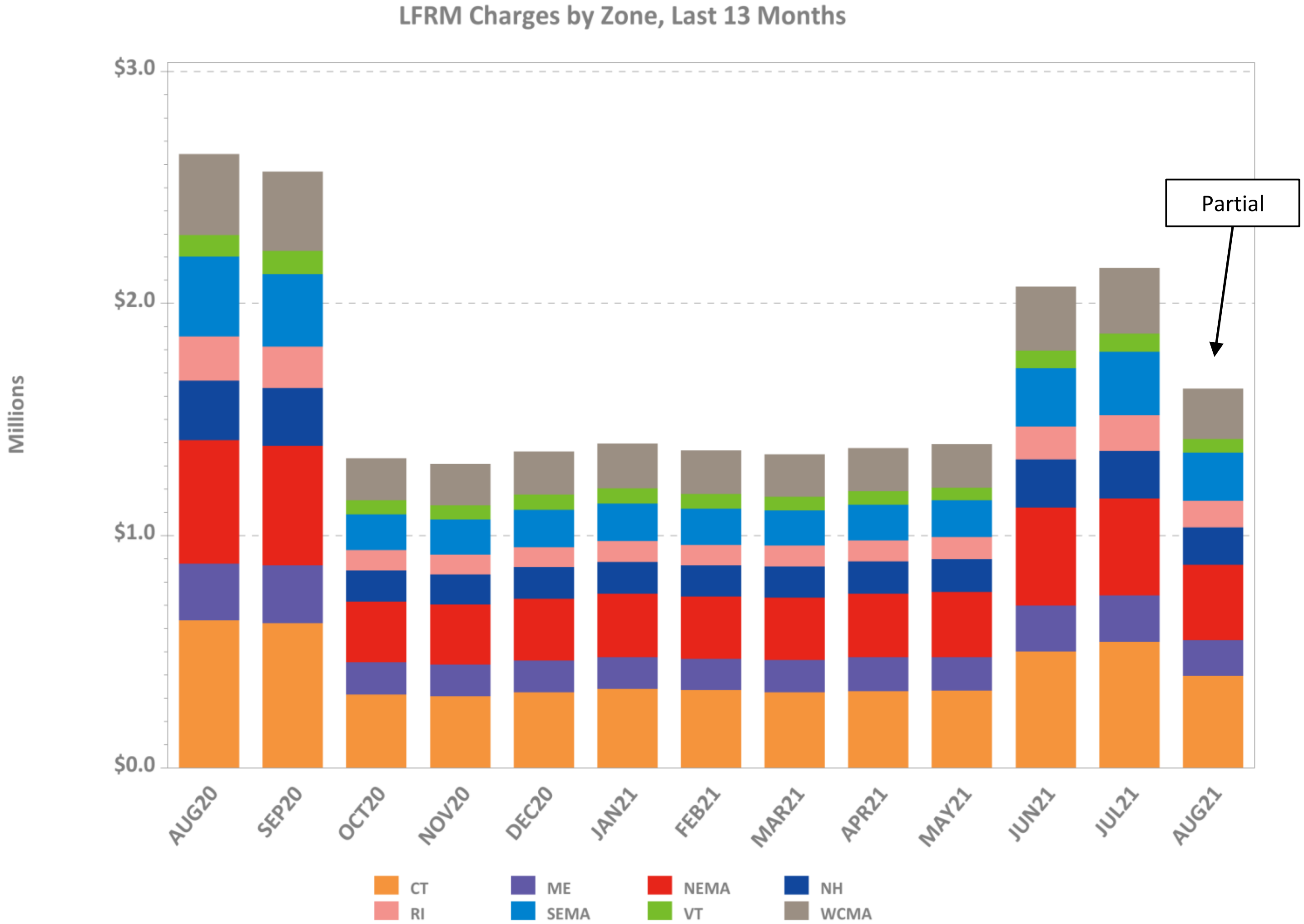
*Forecasted New England daily peak hours reflected

Reserve Market Results – August 2021

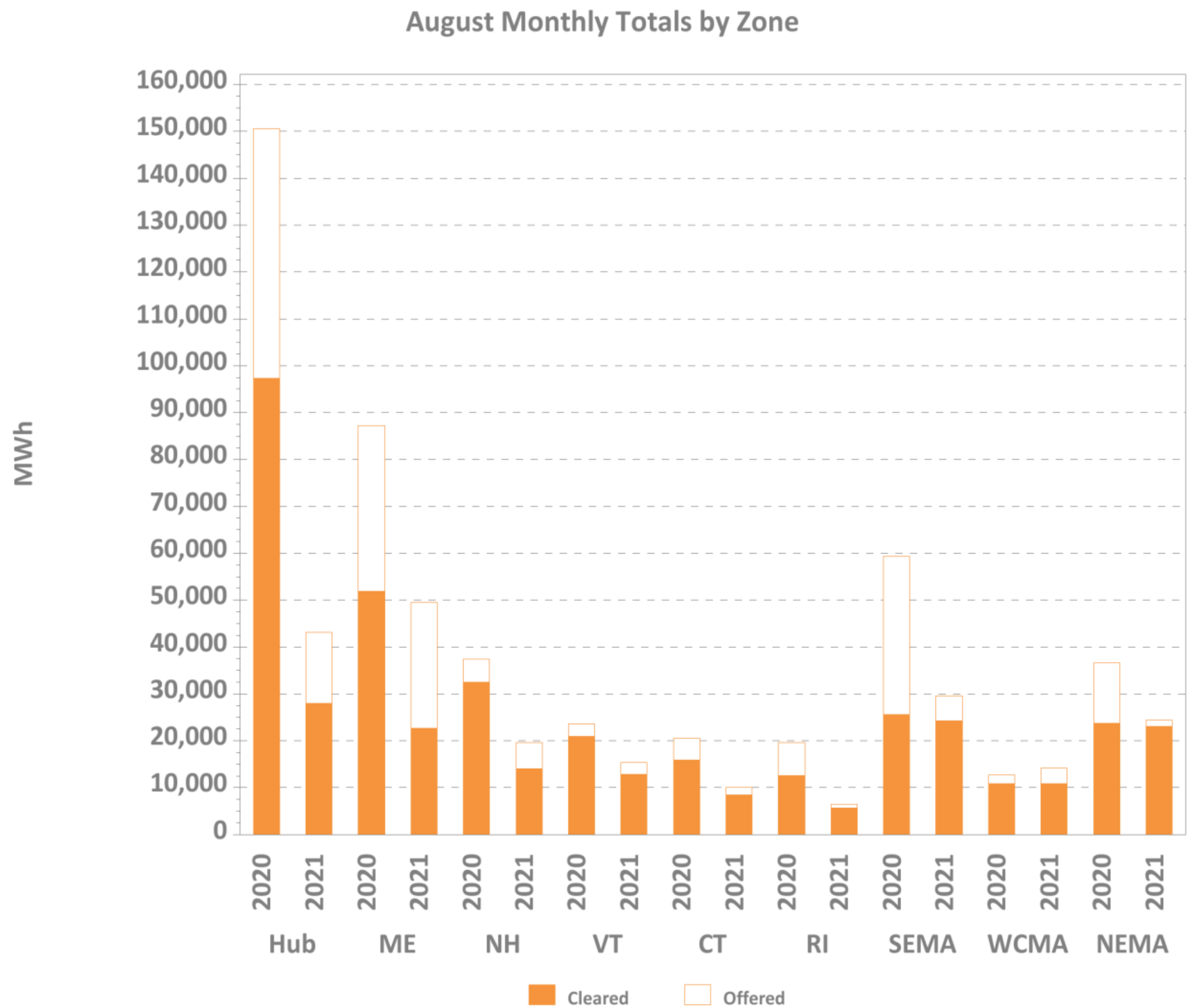
- Maximum potential Forward Reserve Market payments of $1.9M were reduced by credit reductions of $26K, failure-to-reserve penalties of $126K and failure-to-activate penalties of $72K, resulting in a net payout of $1.6M or 88% of maximum
  - Rest of System: $1.25M/1.45M (86%)
  - Southwest Connecticut: $0.04M/0.04M (96%)
  - Connecticut: $0.33M/0.35M (94%)
- $3.7M total Real-Time credits were reduced by $1.2M in Forward Reserve Energy Obligation Charges for a net of $2.5M in Real-Time Reserve payments
  - Rest of System: 209 hours, $1.5M
  - Southwest Connecticut: 209 hours, $332K
  - Connecticut: 209 hours, $340K
  - NEMA: 209 hours, $350K

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.

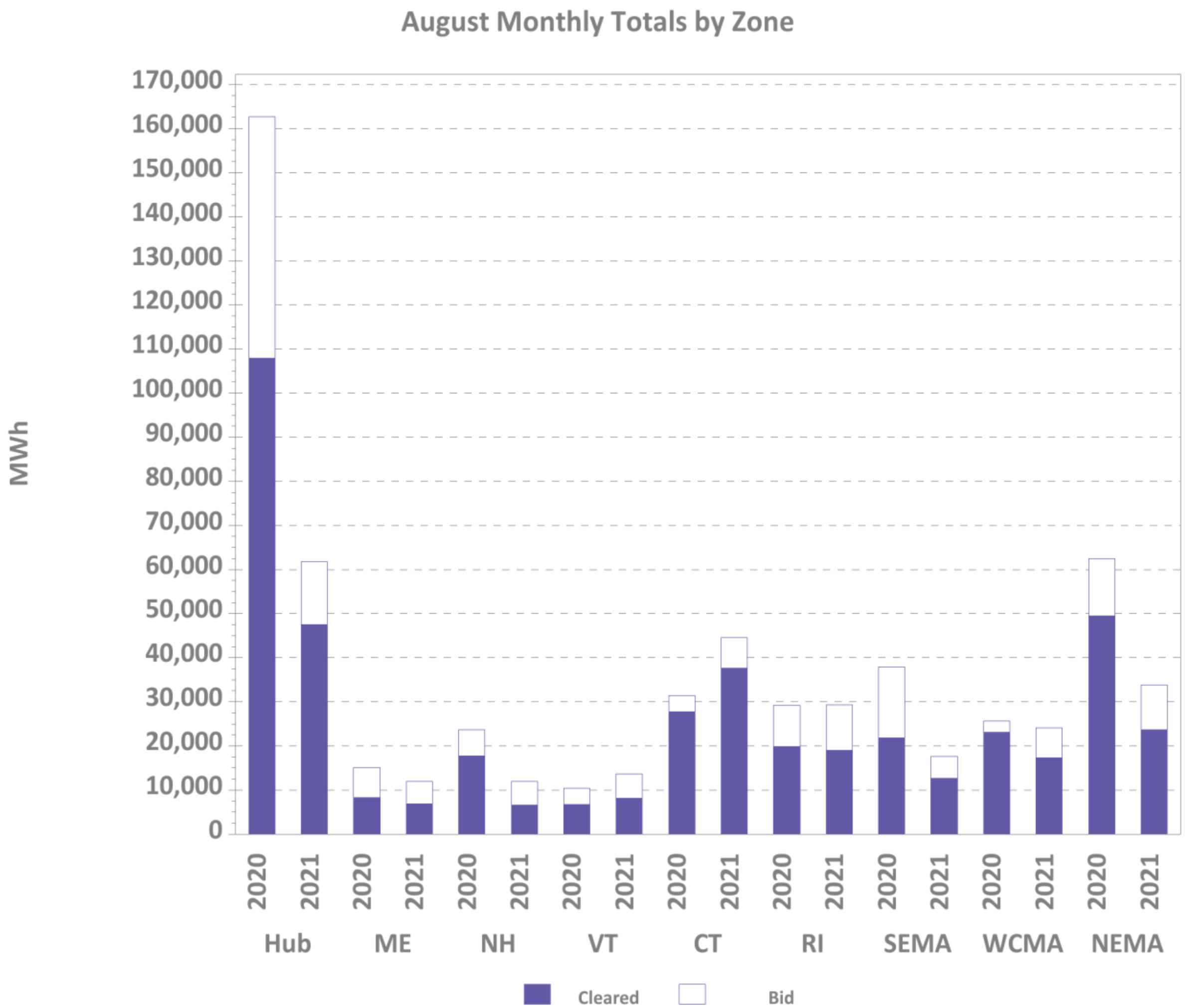
LFRM Charges to Load by Load Zone ($)



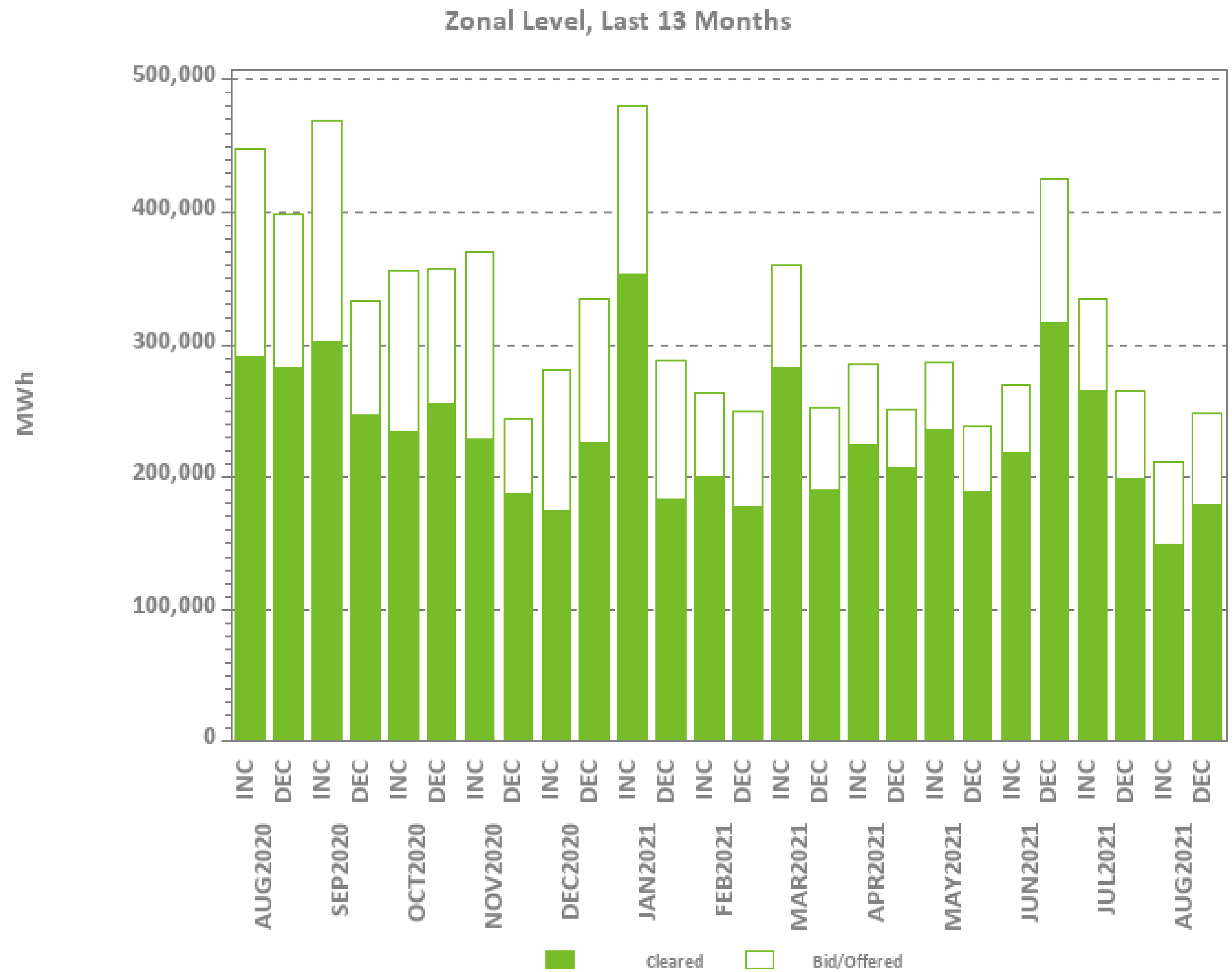
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

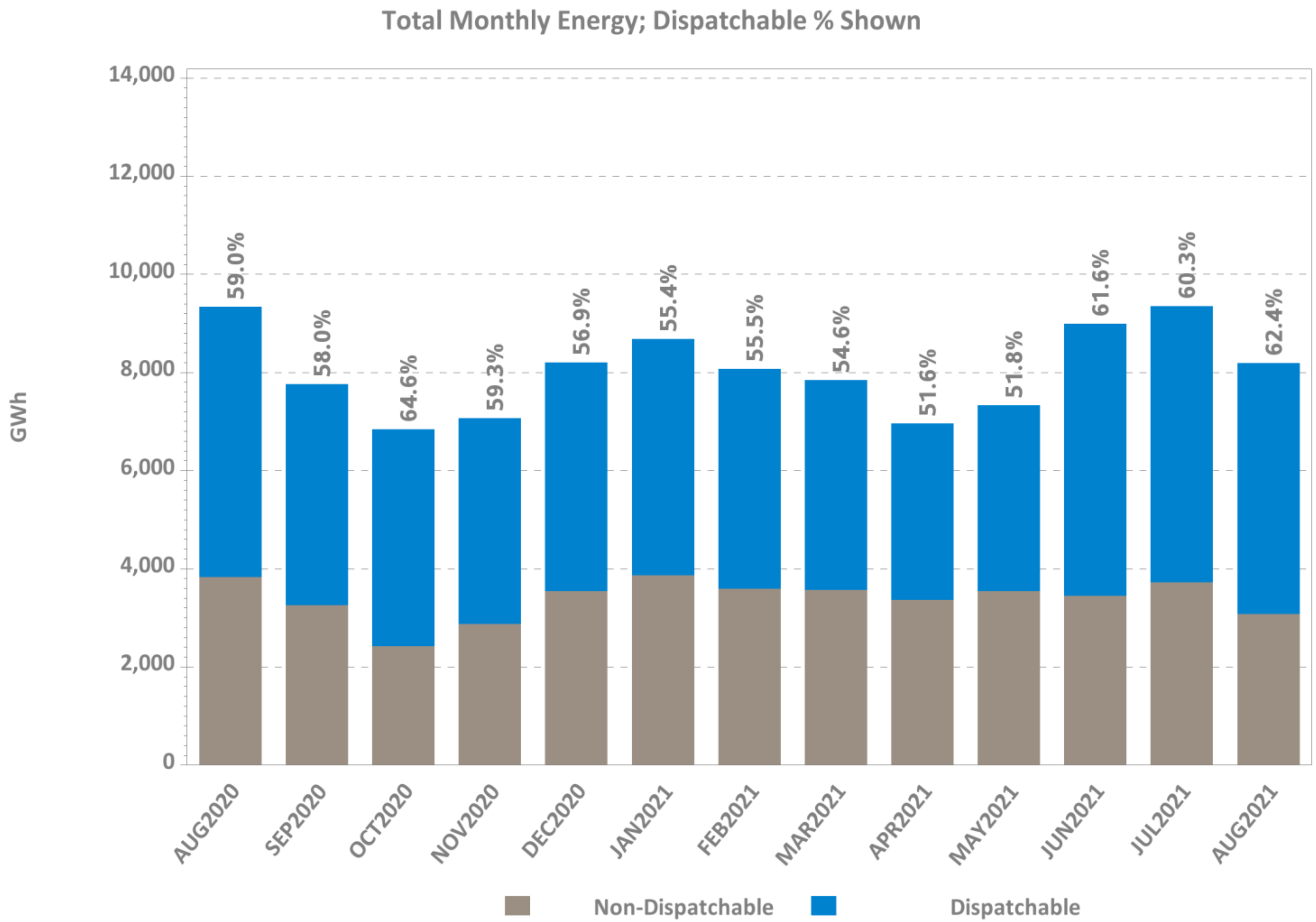


Total Increment Offers and Decrement Bids



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)

- RSP21 development continues and the document is being finalized based on comments received at the August 18 PAC meeting
- RSP21 Public Meeting will be held virtually on October 6
  - Keynote speaker has yet to be named. Panelists have been designated and include:
    - Bill Magness, former CEO, ERCOT
    - Jim Robb, CEO, NERC
    - Charlotte Ancel, VP AvanGrid
    - Debra Lew, Associate Director, Energy Systems Integration Group
  - Panel Discussion: Grid of the Future: Preparing and Responding to Extreme Events
  - Registration is open and can be accessed via the ISO-NE website calendar

Planning Advisory Committee (PAC)

- September 17 PAC Meeting Agenda Topics*
  - 2021 Economic Study: Future Grid Reliability Study Phase 1 - Ancillary Services Preliminary Results - Part 1
  - 2021 Economic Study: Future Grid Reliability Study Phase 1 - Production Cost Preliminary Results - Part 3
- September 22 PAC Meeting Agenda Topics*
  - A-1 & B-2 69 kV Line Asset Condition Project
  - UI's 115 kV Derby Junction to Ansonia Corridor Needs & Solutions Update
  - Moore #20 Substation Asset Separation
  - Southwest Connecticut Substation Relay Upgrades
  - K42 Line Refurbishment
  - Revised SEMA/RI 2029 Needs Assessment Update Addendum
  - Western and Central Massachusetts - 2029 Study Update
  - SEMA/RI 2030 Minimum Load Needs Assessment Results
  - FGRS Assumptions for Resource Adequacy Screen and Probabilistic Resource Availability Analysis
  - Curtailment Analysis for Proposed Interconnections - Pilot Study

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

Transmission Planning for the Clean Energy Transition

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

Economic Studies

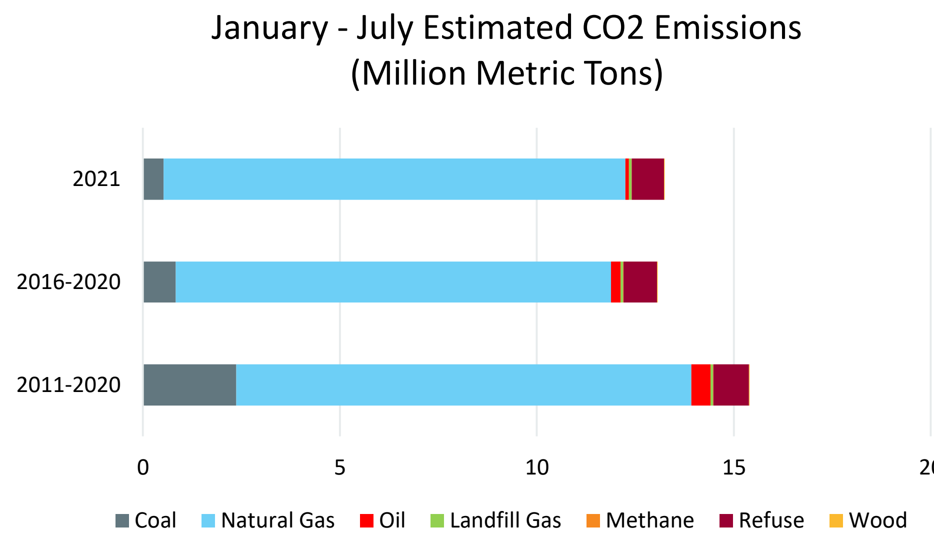
- 2020 Economic Study Request
  - Study proponent is National Grid
  - Study simulations are complete, and results have been presented to PAC
    - Draft report to be completed by the end of 2021
- 2021 Economic Study Request
  - Also known as Future Grid Reliability Study – Phase 1 (FGRS)
  - Study proponent is NEPOOL
    - Preliminary production cost simulation results presented at the June and July PAC meetings; remaining preliminary production cost results will be discussed at a special September 17 PAC meeting
    - Preliminary ancillary services analyses results to be presented at the special September 17 PAC meeting

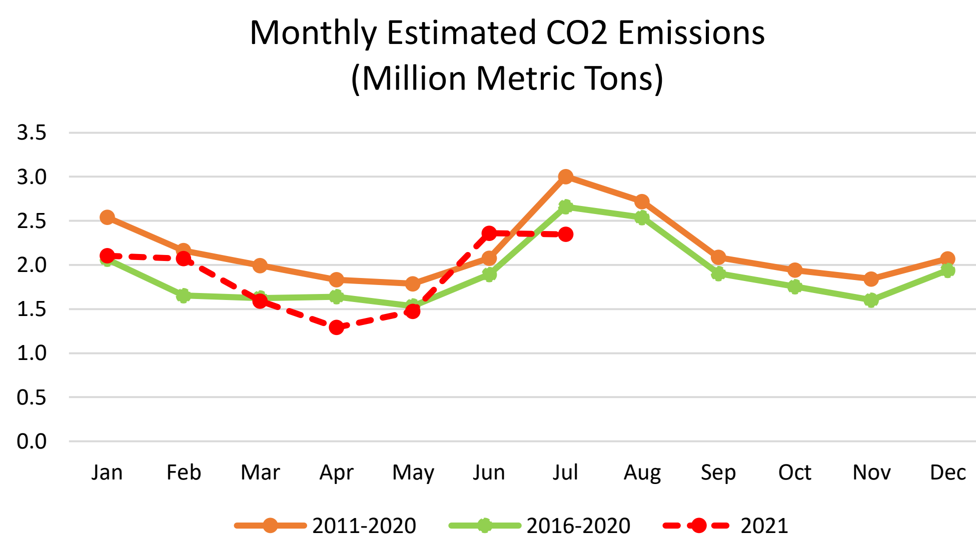
Future Grid Reliability Study (FGRS)

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

Environmental Matters – Shift in Power System Emission Trends

- 2021 power system carbon dioxide (CO_2) emissions increased 1.3% compared to 5-year average (2016-2020)
- Other 2021 system emission trends declined
  - Nitrogen oxide (-7%) and sulfur dioxide (-14%) emissions declined compared to the 2016-2020 average for the same period (January - July)
- 2021 estimated CO_2 emissions driven by greater natural-gas-fired generation compared to 5- and 10-year averages for the same period (January - July)
  - 2021 estimated CO_2 emissions from all other emitting fuel categories declined compared to 5- and 10-year averages



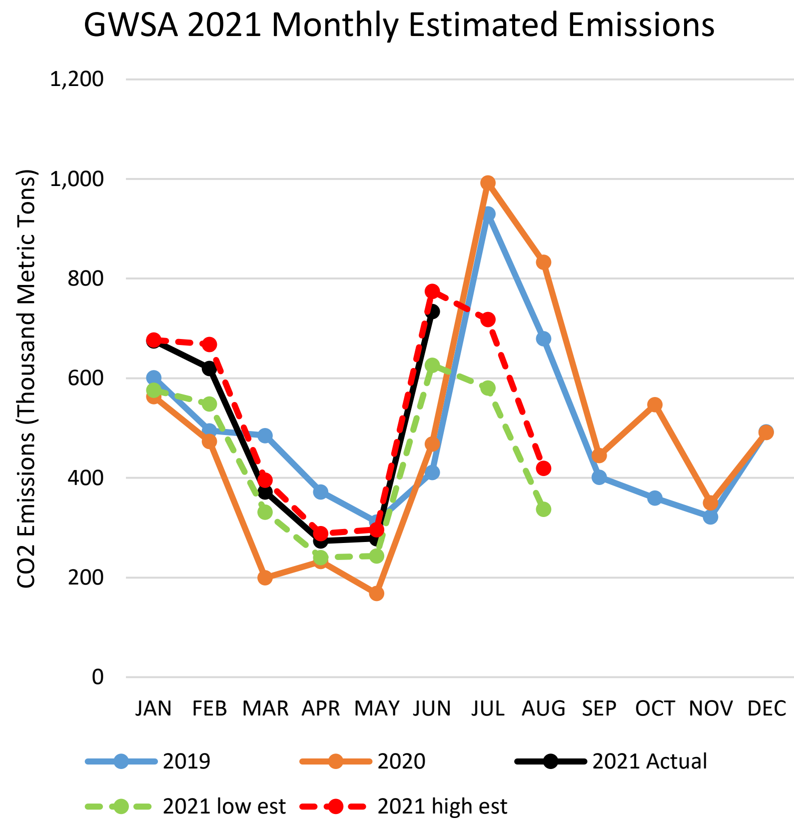


Environmental Matters – Massachusetts CO_2 Generator Emissions Cap

2021 CO_2 GWSA Emissions Trending Lower

- As of 8/16/21, estimated CO_2 emissions range between 3.48 and 4.23 million metric tons (MMT)
  - 42% to 51% of the 8.23 MMT 2021 cap
- 6/9/21: GWSA auction clearing price was $7.75 per metric ton
- Affected generators have access to banked allowances, in excess of expected 2021 emissions
- Range of public comments submitted during GWSA cap program review, and regulators reviewing suggested changes
- No major programmatic changes expected, review scheduled to finish in December 2021

2019-2021 Estimated Monthly Emissions (Thousand Metric Tons)



GWSA - Global Warming Solutions Act

RSP Project Stage Descriptions

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

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

Greater Boston Projects

Status as of 8/23/2021

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1213, 1220, 1365	Install new 345 kV line from Scobie to Tewksbury	Dec-17	4
1527, 1528	Reconductor the Y-151 115 kV line from Dracut Junction to Power Street	Apr-17	4
1212, 1549	Reconductor the M-139 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
1549	Reconductor the N-140 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
1260	Reconductor the F-158N 115 kV line from Wakefield Junction to Maplewood and associated work at Maplewood	Dec-15	4
1550	Reconductor the F-158S 115 kV line from Maplewood to Everett	Jun-19	4
1551, 1552	Install new 345 kV cable from Woburn to Wakefield Junction, install two new 160 MVAR variable shunt reactors and associated work at Wakefield Junction and Woburn*	May-22	3*
1329	Refurbish X-24 69 kV line from Millbury to Northboro Road	Dec-15	4
1327	Reconductor W-23W 69 kV line from Woodside to Northboro Road	Jun-19	4

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

Greater Boston Projects, cont.

Status as of 8/23/2021

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1330	Separate X-24 and E-157W DCT	Dec-18	4
1363	Separate Q-169 and F-158N DCT	Dec-15	4
1637, 1640	Reconductor M-139/211-503 and N-140/211-504 115 kV lines from Pinehurst to North Woburn tap	May-17	4
1516	Install new 115 kV station at Sharon to segment three 115 kV lines from West Walpole to Holbrook	Sep-20	4
965	Install third 115 kV line from West Walpole to Holbrook	Sep-20	4
1558	Install new 345 kV breaker in series with the 104 breaker at Stoughton	May-16	4
1199	Install new 230/115 kV autotransformer at Sudbury and loop the 282-602 230 kV line in and out of the new 230 kV switchyard at Sudbury	Dec-17	4
1335	Install a new 115 kV line from Sudbury to Hudson	Dec-23	2

Greater Boston Projects, cont.

Status as of 8/23/2021

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1336	Replace 345/115 kV autotransformer, 345 kV breakers, and 115 kV switchgear at Woburn	Dec-19	4
1553	Install a 345 kV breaker in series with breaker 104 at Woburn	Jun-17	4
1337	Reconfigure Waltham by relocating PARs, 282-507 line, and a breaker	Dec-17	4
1339	Upgrade 533-508 115 kV line from Lexington to Hartwell and associated work at the stations	Aug-16	4
1521	Install a new 115 kV 54 MVAR capacitor bank at Newton	Dec-16	4
1522	Install a new 115 kV 36.7 MVAR capacitor bank at Sudbury	May-17	4
1352	Install a second Mystic 345/115 kV autotransformer and reconfigure the bus	May-19	4
1353	Install a 115 kV breaker on the East bus at K Street	Jun-16	4
1354, 1738	Install 115 kV cable from Mystic to Chelsea and upgrade Chelsea 115 kV station to BPS standards	Jul-21	4
1355	Split 110-522 and 240-510 DCT from Baker Street to Needham for a portion of the way and install a 115 kV cable for the rest of the way	Mar-21	4

Greater Boston Projects, cont.

Status as of 8/23/2021

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1356	Install a second 115 kV cable from Mystic to Woburn to create a bifurcated 211-514 line	May-22	3
1357	Open lines 329-510/511 and 250-516/517 at Mystic and Chatham, respectively. Operate K Street as a normally closed station.	May-19	4
1518	Upgrade Kingston to create a second normally closed 115 kV bus tie and reconfigure the 345 kV switchyard	Mar-19	4
1519	Relocate the Chelsea capacitor bank to the 128-518 termination postion	Dec-16	4

Greater Boston Projects, cont.

Status as of 8/23/2021

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

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

SEMA/RI Reliability Projects

Status as of 8/23/2021

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

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

SEMA/RI Reliability Projects, cont.

Status as of 8/23/2021

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1718	Add 115 kV circuit breaker at Robinson Ave substation and re-terminate the Q10 line	Mar-22	3
1719	Install 45.0 MVAR capacitor bank at Berry Street substation	Cancelled*	N/A
1720	Separate the N12/M13 DCT and reconductor the N12 and M13 between Somerset and Bell Rock substations	May-25	2
1721	Reconfigure Bell Rock to breaker-and-a-half station, split the M13 line at Bell Rock substation, and terminate 114 line at Bell Rock; install a new breaker in series with N12/D21 tie breaker, upgrade D21 line switch, and install a 37.5 MVAR capacitor	Dec-23	2
1722	Extend the Line 114 from the Dartmouth town line (Eversource- NGRID border) to Bell Rock substation	Dec-23	2
1723	Reconductor L14 and M13 lines from Bell Rock substation to Bates Tap	Cancelled*	N/A

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

SEMA/RI Reliability Projects, cont.

Status as of 8/23/2021

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1725	Build a new 115 kV line from Bourne to West Barnstable substations which includes associated terminal work	Dec-23	1
1726	Separate the 135/122 DCT from West Barnstable to Barnstable substations	Dec-21	3
1727	Retire the Barnstable SPS	Dec-21	3
1728	Build a new 115 kV line from Carver to Kingston substations and add a new Carver terminal	Dec-22	1
1729	Install a new bay position at Kingston substation to accommodate new 115 kV line	Dec-22	1
1730	Extend the 114 line from the Eversource/National Grid border to the Industrial Park Tap	Dec-23	1

SEMA/RI Reliability Projects, cont.

Status as of 8/23/2021

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

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

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

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

SEMA/RI Reliability Projects, cont.

Status as of 8/23/2021

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1741	Rebuild the Middleborough Gas and Electric portion of the E1 line from Bridgewater to Middleborough	Apr-19	4
1782	Reconductor the J16S line	Jun-22	2
1724	Replace the Kent County 345/115 kV transformer	Mar-22	2
1789	West Medway 345 kV circuit breaker upgrades	Apr-21	4
1790	Medway 115 kV circuit breaker replacements	Nov-20	4

Eastern CT Reliability Projects

Status as of 8/23/2021

Project Benefit: Addresses system needs in the Eastern Connecticut area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1815	Reconductor the L190-4 and L190-5 line sections	Dec-26	1
1850	Install a second 345/115 kV autotransformer (4X) and one 345 kV breaker at Card substation	Mar-23	2
1851	Upgrade Card 115 kV to BPS standards	Mar-23	2
1852	Install one 115 kV circuit breaker in series with Card substation 4T	Mar-23	2
1853	Convert Gales Ferry substation from 69 kV to 115 kV	Dec-23	1
1854	Rebuild the 100 Line from Montville to Gales Ferry to allow operation at 115 kV	Dec-22	1

Eastern CT Reliability Projects, cont.

Status as of 8/23/2021

Project Benefit: Addresses system needs in the Eastern Connecticut area

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

Eastern CT Reliability Projects, cont.

Status as of 8/23/2021

Project Benefit: Addresses system needs in the Eastern Connecticut area

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

Boston Area Optimized Solution Projects

Status as of 8/23/2021

Project Benefit: Addresses system needs in the Boston area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1874	Install two 11.9 ohm series reactors at North Cambridge Station on Lines 346 and 365	Jun-23	3
1875	Install a direct transfer trip (DTT) scheme between Ward Hill and West Amesbury Substations for Line 394	Jan-23	1
1876	Install one +/- 167 MVAR STATCOM at Tewksbury 345 kV Substation	Oct-23	1

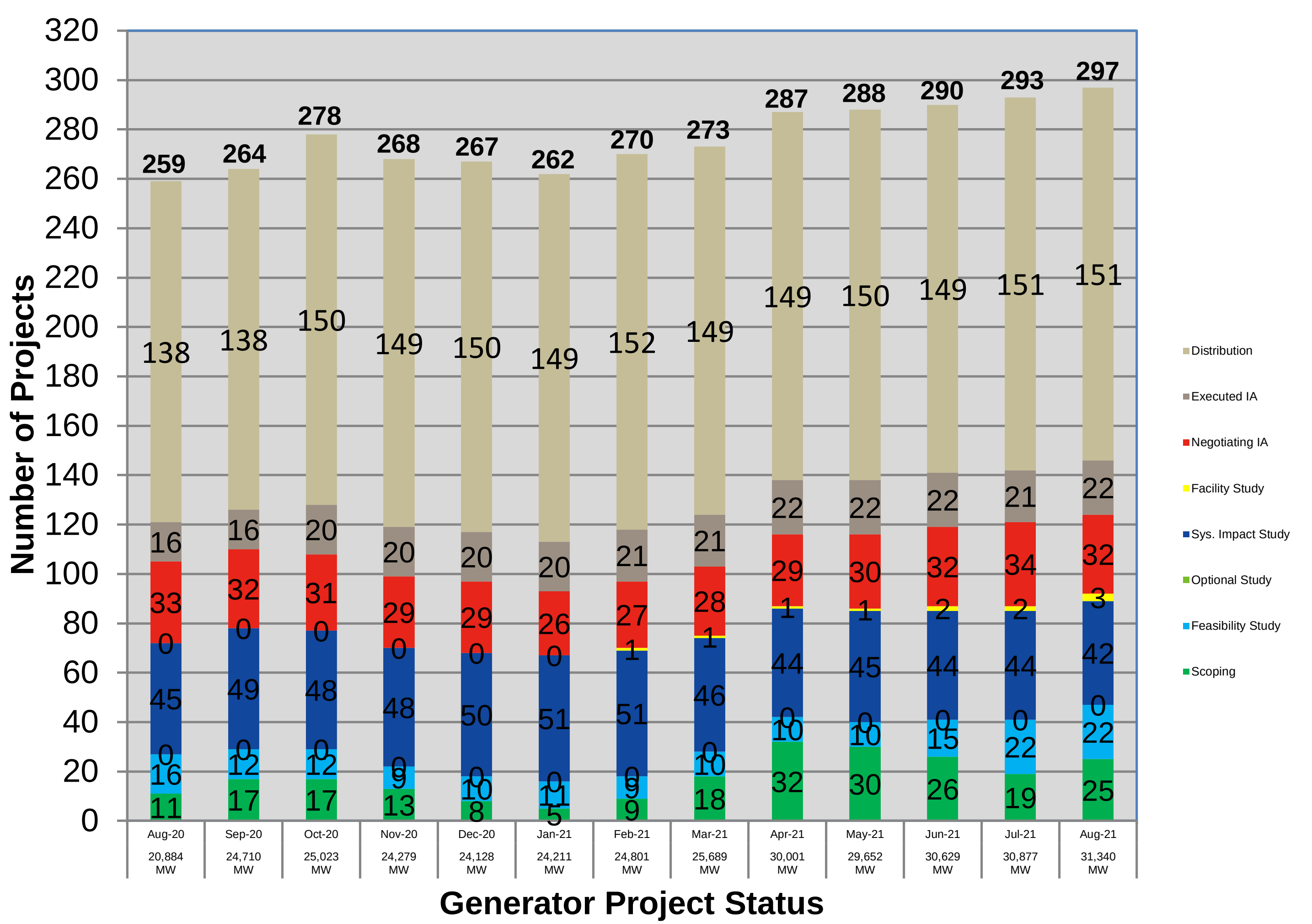
New Hampshire Solution Projects

Status as of 8/23/2021

Project Benefit: Addresses system needs in the New Hampshire area

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

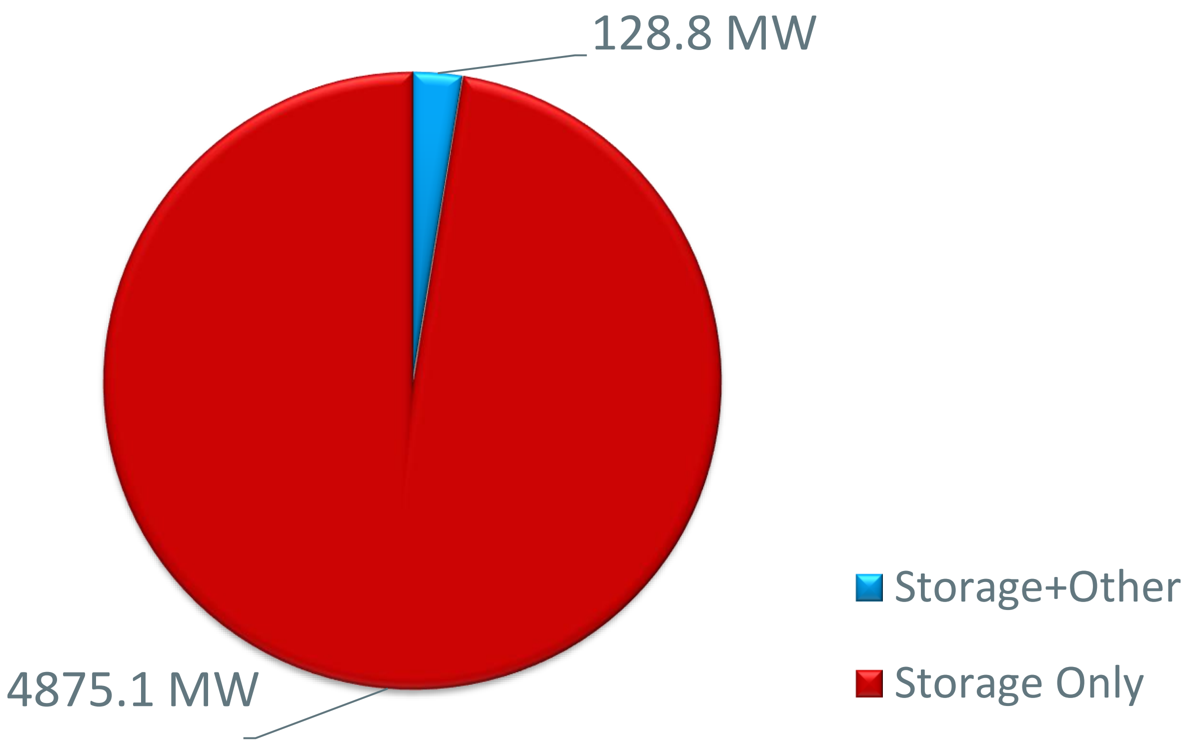
Status of Tariff Studies



Note: August 2021 is based on partial data.
As of August 2021, there is 2 ETU in Scoping, 0 in FS, 3 in SIS, 0 in OIS, 1 in FAC, 0 Negotiating IA, and 2 with Executed IA.
https://irtt.iso-ne.com/external.aspx

What is in the Queue (as of August 25, 2021)

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



OPERABLE CAPACITY ANALYSIS

Fall 2021 Analysis

Fall 2021 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Sep. - 2021[2] CSO (MW)	Sep. - 2021[2] SCC (MW)
Operable Capacity MW [1]	29,131	30,065
Active Demand Capacity Resource (+) [5]	491	487
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	768	768
Non Commercial Capacity (+)	48	48
Non Gas-fired Planned Outage MW (-)	3,207	3,835
Gas Generator Outages MW (-)	1,847	1,896
Allowance for Unplanned Outages (-) [4]	2,100	2,100
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	23,284	23,537
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,658	20,658
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,963	22,963
Operable Capacity Margin	321	574

[1]Operable Capacity is based on data as of **August 24, 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 **August 24, 2021.**

[2] Load forecast that is based on the 2021 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **September 25, 2021.**

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

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

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

Fall 2021 Operable Capacity Analysis

90/10 Load Forecast	Sep. - 2021[2] CSO (MW)	Sep. - 2021[2] SCC (MW)
Operable Capacity MW [1]	29,131	30,065
Active Demand Capacity Resource (+) [5]	491	487
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	768	768
Non Commercial Capacity (+)	48	48
Non Gas-fired Planned Outage MW (-)	3,207	3,835
Gas Generator Outages MW (-)	1,847	1,896
Allowance for Unplanned Outages (-) [4]	2,100	2,100
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	23,284	23,537
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	22,280	22,280
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	24,585	24,585
Operable Capacity Margin	-1,301	-1,048

[1]Operable Capacity is based on data as of **August 24, 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 **August 24, 2021.**

[2] Load forecast that is based on the 2021 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **September 25, 2021.**

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

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

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

Fall 2021 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

August 27, 2021 - 50-50 FORECAST using CSO MW

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

Study Week (Week Beginning, Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 50-50PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 50-50PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
9/18/2021	29131	491	768	48	2625	1881	2100	0	23832	20751	2305	23056	776	N	Fall 2021
9/25/2021	**29131**	**491**	**768**	**48**	**3207**	**1847**	**2100**	**0**	**23284**	**20658**	**2305**	**22963**	**321**	**Y**	**Fall 2021**
10/2/2021	29750	540	1135	50	5428	3044	2800	0	20203	14789	2305	17094	3110	N	Fall 2021
10/9/2021	29750	540	1135	50	5485	3044	2800	0	20146	14825	2305	17130	3017	N	Fall 2021
10/16/2021	29750	540	1135	50	5570	3480	2800	0	19624	15749	2305	18054	1571	N	Fall 2021
10/23/2021	29750	540	1078	50	5458	2326	2800	0	20834	16113	2305	18418	2417	N	Fall 2021
10/30/2021	29750	540	1135	50	4370	1304	3600	0	22201	16320	2305	18625	3576	N	Fall 2021
11/6/2021	29750	540	1135	50	2235	1277	3600	0	24363	16435	2305	18740	5624	N	Fall 2021
11/13/2021	29750	540	1135	50	1241	1051	3600	0	25584	16780	2305	19085	6499	N	Fall 2021
11/20/2021	29750	540	1135	50	1057	610	3600	816	25392	17517	2305	19822	5570	N	Fall 2021

Column Definitions

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

Fall 2021 Operable Capacity Analysis
90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

August 27, 2021 - 90/10 FORECAST using CSO MW

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

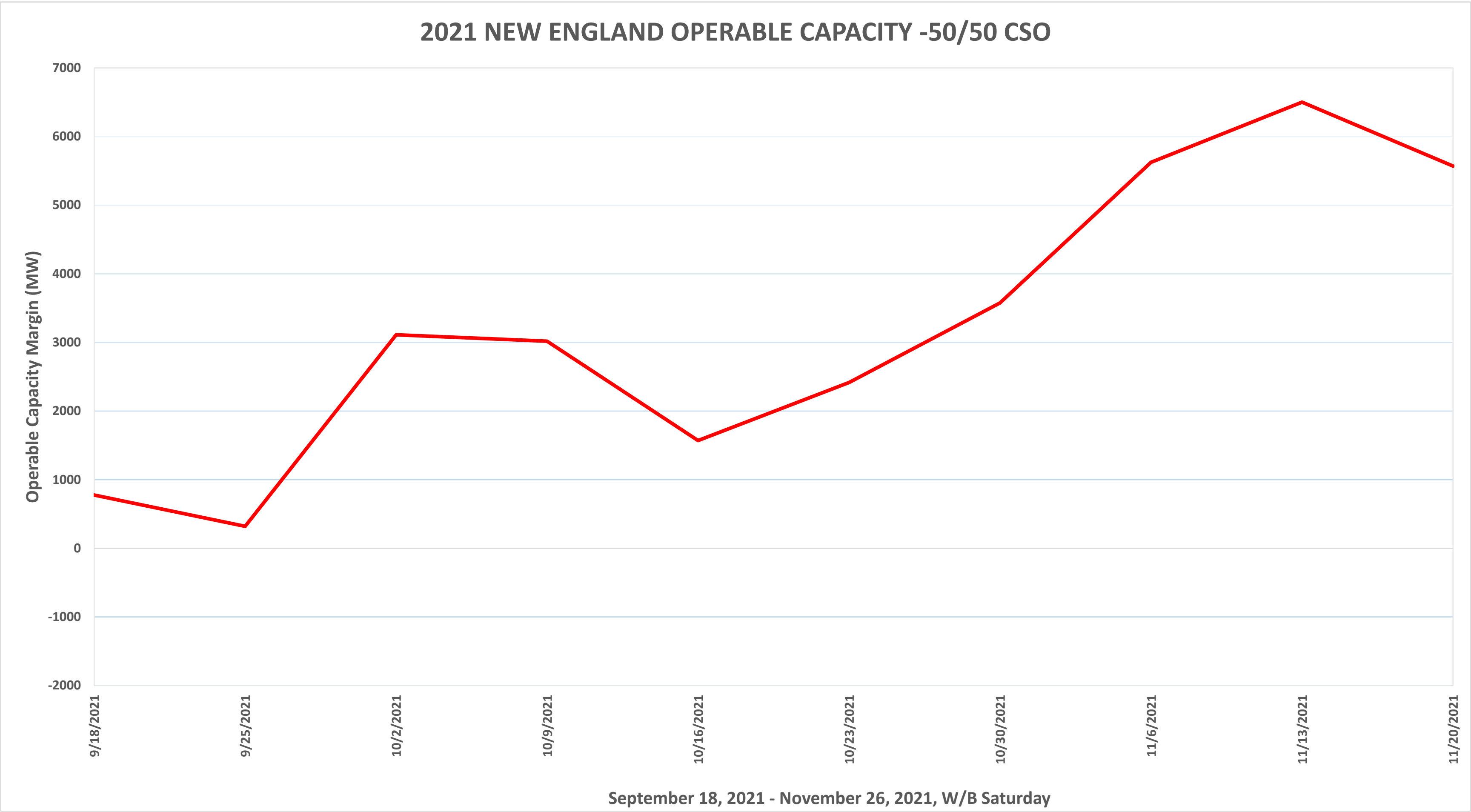
Study Week (Week Beginning, Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 90-10PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 90-10PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
9/18/2021	29131	491	768	48	2625	1881	2100	0	23832	22380	2305	24685	-853	N	Fall 2021
9/25/2021	**29131**	**491**	**768**	**48**	**3207**	**1847**	**2100**	**0**	**23284**	**22280**	**2305**	**24585**	**-1301**	**Y**	**Fall 2021**
10/2/2021	29750	540	1135	50	5428	3044	2800	0	20203	15292	2305	17597	2607	N	Fall 2021
10/9/2021	29750	540	1135	50	5485	3044	2800	0	20146	15328	2305	17633	2514	N	Fall 2021
10/16/2021	29750	540	1135	50	5570	3480	2800	0	19624	16279	2305	18584	1041	N	Fall 2021
10/23/2021	29750	540	1078	50	5458	2326	2800	0	20834	16654	2305	18959	1876	N	Fall 2021
10/30/2021	29750	540	1135	50	4370	1304	3600	0	22201	16866	2305	19171	3030	N	Fall 2021
11/6/2021	29750	540	1135	50	2235	1277	3600	0	24363	16985	2305	19290	5074	N	Fall 2021
11/13/2021	29750	540	1135	50	1241	1051	3600	131	25452	17339	2305	19644	5809	N	Fall 2021
11/20/2021	29750	540	1135	50	1057	610	3600	987	25221	18098	2305	20403	4818	N	Fall 2021

Column Definitions

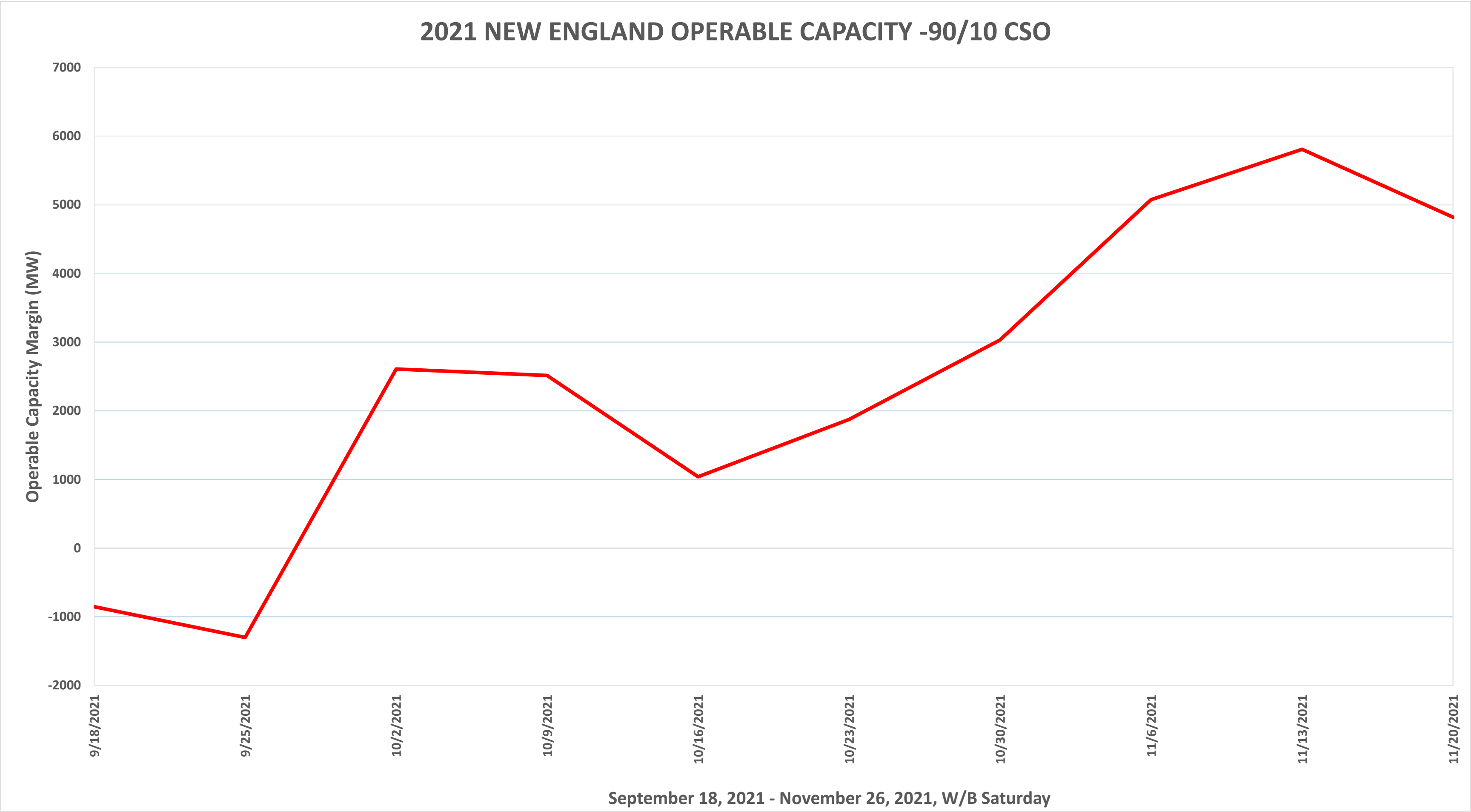
1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can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

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

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



Fall 2021 Operable Capacity Analysis
90/10 Forecast



OPERABLE CAPACITY ANALYSIS

Preliminary Winter 2021/22 Analysis

Preliminary Winter 2021/22 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Jan. - 2022[2] CSO (MW)	Jan. - 2022[2] SCC (MW)
Operable Capacity MW [1]	29,774	32,812
Active Demand Capacity Resource (+) [5]	541	401
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,135	1,135
Non Commercial Capacity (+)	50	50
Non Gas-fired Planned Outage MW (-)	303	1,015
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	3,887	4,439
Net Capacity (NET OPCAP SUPPLY MW)	24,510	26,144
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	19,710	19,710
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,015	22,015
Operable Capacity Margin	2,495	4,129

[1]Operable Capacity is based on data as of **August 24, 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 **August 24, 2021.**

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

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

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

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

Preliminary Winter 2021/22 Operable Capacity Analysis

90/10 Load Forecast	Jan. - 2022[2] CSO (MW)	Jan. - 2022[2] SCC (MW)
Operable Capacity MW [1]	29,774	32,812
Active Demand Capacity Resource (+) [5]	541	401
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,135	1,135
Non Commercial Capacity (+)	50	50
Non Gas-fired Planned Outage MW (-)	303	1,015
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	4,594	5,246
Net Capacity (NET OPCAP SUPPLY MW)	23,803	25,337
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,349	20,349
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,654	22,654
Operable Capacity Margin	1,149	2,683

[1]Operable Capacity is based on data as of **August 24, 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 **August 24, 2021.**

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

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

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

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

Preliminary Winter 2021/22 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

August 27, 2021 - 50-50 FORECAST using CSO MW

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

Study Week (Week Beginning, Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 50-50PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 50-50PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
11/27/2021	29750	540	1135	50	1085	8	3600	2030	24752	18237	2305	20542	4210	N	Winter 2021/2022
12/4/2021	29774	541	1135	50	369	272	3200	2206	25453	18611	2305	20916	4537	N	Winter 2021/2022
12/11/2021	29774	541	1135	50	340	0	3200	2685	25275	18900	2305	21205	4070	N	Winter 2021/2022
12/18/2021	29774	541	1135	50	320	0	3200	2908	25072	18911	2305	21216	3856	N	Winter 2021/2022
12/25/2021	29774	541	1135	50	320	0	3200	3269	24711	18973	2305	21278	3433	N	Winter 2021/2022
1/1/2022	29774	541	1135	50	332	0	2800	3892	24476	19246	2305	21551	2925	N	Winter 2021/2022
1/8/2022	**29774**	**541**	**1135**	**50**	**303**	**0**	**2800**	**3887**	**24510**	**19710**	**2305**	**22015**	**2495**	**Y**	**Winter 2021/2022**
1/15/2022	29774	541	1135	50	303	0	2800	3736	24661	19710	2305	22015	2646	N	Winter 2021/2022
1/22/2022	29774	541	1135	50	303	0	2800	3269	25128	19710	2305	22015	3113	N	Winter 2021/2022
1/29/2022	29774	541	1135	50	303	0	3100	2958	25139	19488	2305	21793	3346	N	Winter 2021/2022
2/5/2022	29774	541	1135	50	303	0	3100	2646	25451	19222	2305	21527	3924	N	Winter 2021/2022
2/12/2022	29774	541	1135	50	296	0	3100	2335	25769	19193	2305	21498	4271	N	Winter 2021/2022
2/19/2022	29774	541	1135	50	298	0	3100	1868	26234	18931	2305	21236	4998	N	Winter 2021/2022
2/26/2022	29774	541	1135	50	353	0	3100	1557	26490	17944	2305	20249	6241	N	Winter 2021/2022
3/5/2022	29774	541	1135	50	364	270	2200	975	27691	17596	2305	19901	7790	N	Winter 2021/2022
3/12/2022	29774	541	1135	50	648	718	2200	0	27935	17400	2305	19705	8230	N	Winter 2021/2022
3/19/2022	29774	541	1135	50	1072	1120	2200	0	27108	17036	2305	19341	7767	N	Winter 2021/2022
3/26/2022	29750	540	1135	50	1712	6	2700	0	27056	16472	2305	18777	8280	N	Winter 2021/2022

Column Definitions

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

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

ISO-NE OPERABLE CAPACITY ANALYSIS

August 27, 2021 - 90/10 FORECAST using CSO MW

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

Study Week (Week Beginning, Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 90-10PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 90-10PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
11/27/2021	29750	540	1135	50	1085	8	3600	2391	24391	18838	2305	21143	3248	N	Winter 2021/2022
12/4/2021	29774	541	1135	50	369	272	3200	2717	24942	19218	2305	21523	3419	N	Winter 2021/2022
12/11/2021	29774	541	1135	50	340	0	3200	3507	24453	19515	2305	21820	2633	N	Winter 2021/2022
12/18/2021	29774	541	1135	50	320	0	3200	3713	24267	19527	2305	21832	2435	N	Winter 2021/2022
12/25/2021	29774	541	1135	50	320	0	3200	4072	23908	19591	2305	21896	2012	N	Winter 2021/2022
1/1/2022	29774	541	1135	50	332	0	2800	4462	23906	19872	2305	22177	1729	N	Winter 2021/2022
1/8/2022	**29774**	**541**	**1135**	**50**	**303**	**0**	**2800**	**4594**	**23803**	**20349**	**2305**	**22654**	**1149**	**N**	**Winter 2021/2022**
1/15/2022	29774	541	1135	50	303	0	2800	4731	23666	20349	2305	22654	1012	Y	Winter 2021/2022
1/22/2022	29774	541	1135	50	303	0	2800	4515	23882	20349	2305	22654	1228	N	Winter 2021/2022
1/29/2022	29774	541	1135	50	303	0	3100	4203	23894	20121	2305	22426	1468	N	Winter 2021/2022
2/5/2022	29774	541	1135	50	303	0	3100	4203	23894	19847	2305	22152	1742	N	Winter 2021/2022
2/12/2022	29774	541	1135	50	296	0	3100	3736	24368	19817	2305	22122	2246	N	Winter 2021/2022
2/19/2022	29774	541	1135	50	298	0	3100	3425	24677	19547	2305	21852	2825	N	Winter 2021/2022
2/26/2022	29774	541	1135	50	353	0	3100	2802	25245	18533	2305	20838	4407	N	Winter 2021/2022
3/5/2022	29774	541	1135	50	364	270	2200	2065	26601	18174	2305	20479	6122	N	Winter 2021/2022
3/12/2022	29774	541	1135	50	648	718	2200	1461	26473	17973	2305	20278	6195	N	Winter 2021/2022
3/19/2022	29774	541	1135	50	1072	1120	2200	437	26671	17598	2305	19903	6768	N	Winter 2021/2022
3/26/2022	29750	540	1135	50	1712	6	2700	1084	25973	17017	2305	19322	6651	N	Winter 2021/2022

Column Definitions

1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM). These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.
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6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
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9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)
10. Peak Load Forecast MW: Provided in the annual 2021 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.
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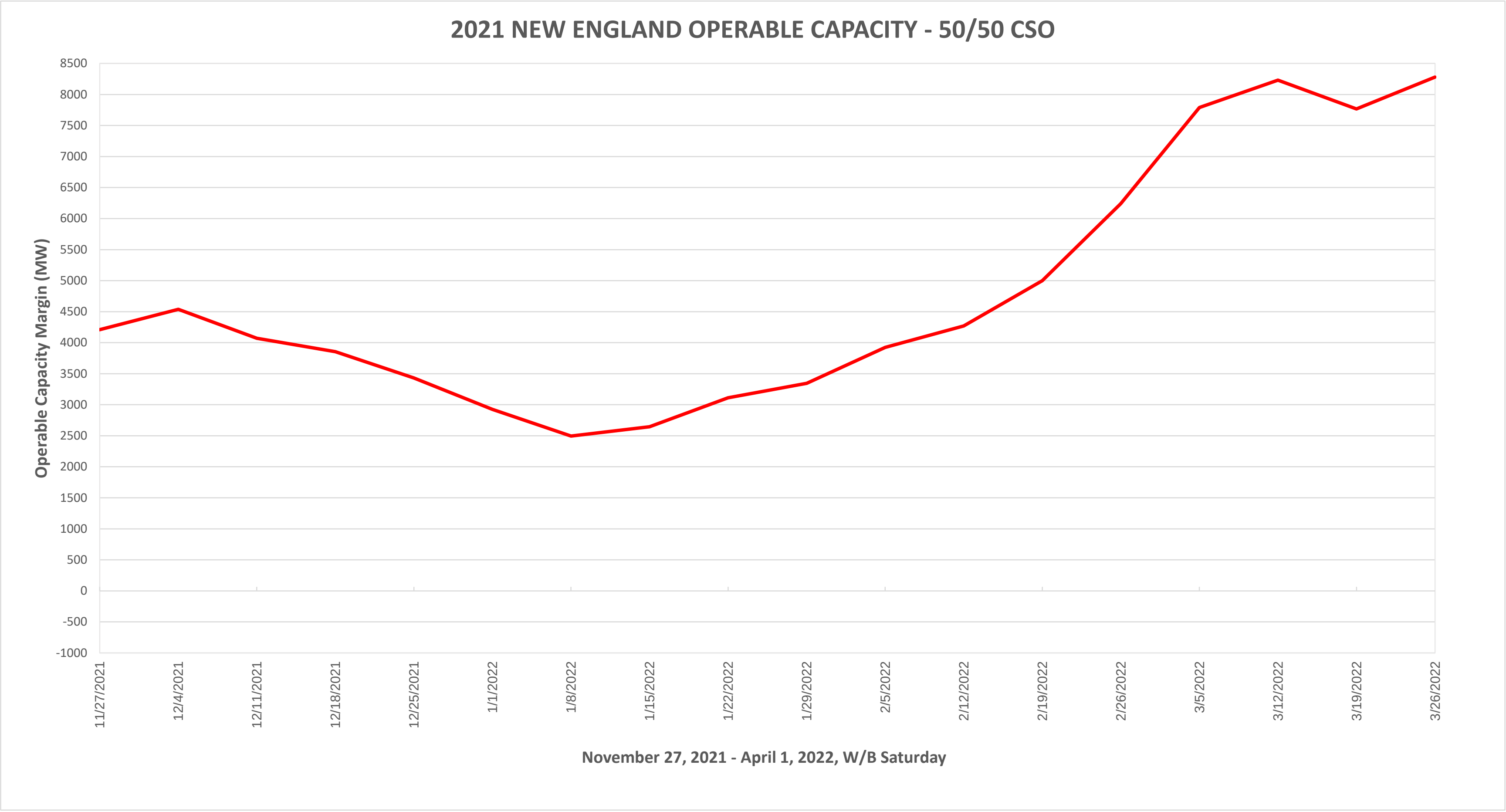
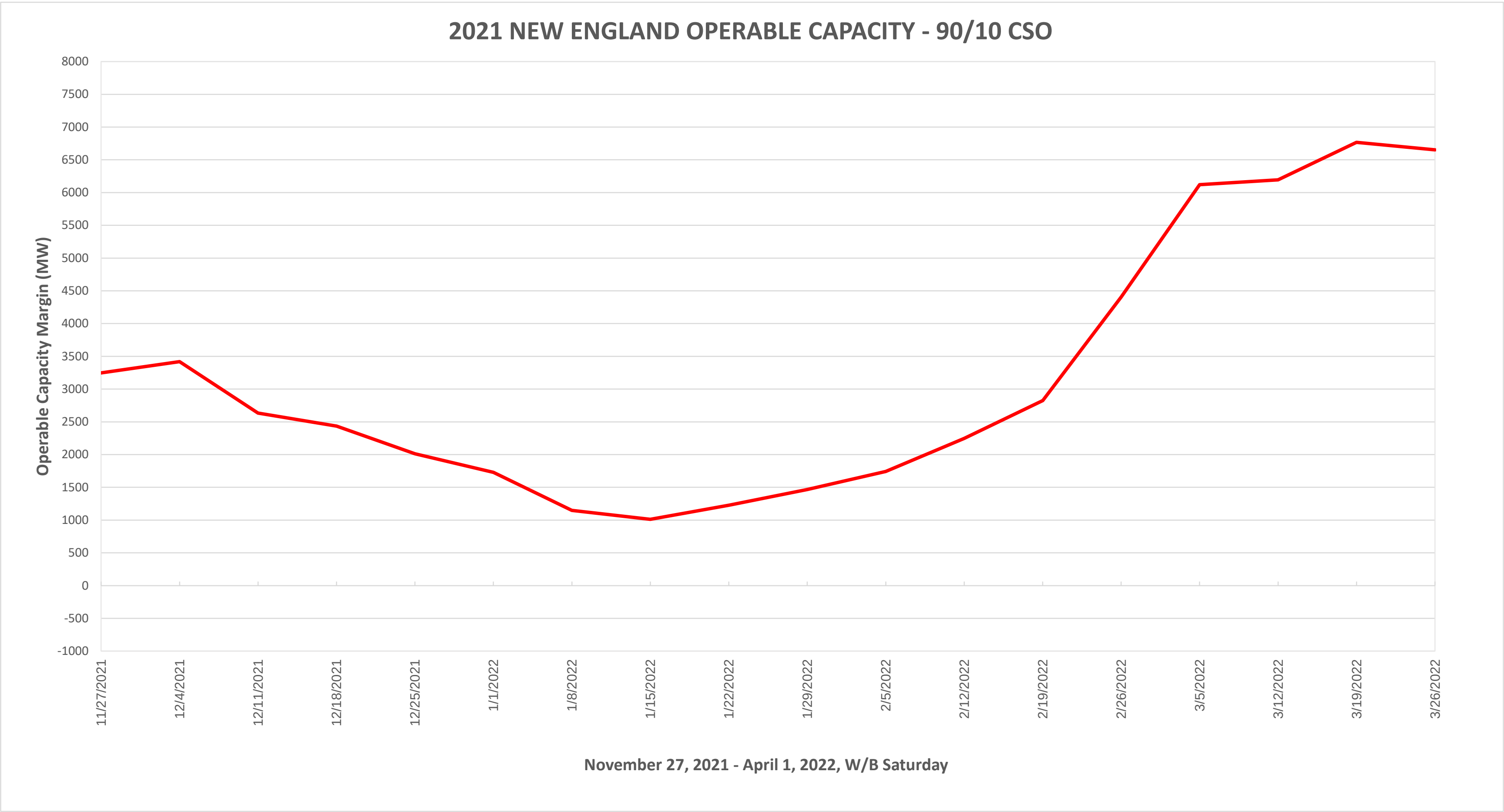
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

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

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



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



OPERABLE CAPACITY ANALYSIS

Appendix

Possible Relief Under OP4: Appendix A

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

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

Possible Relief Under OP4: Appendix A

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

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

ISO new england

memo

To: NEPOOL Participants Committee Members and Alternates

From: Robert C. Ludlow, VP & CF/CO

Date: September 2, 2021

Subject: ISO New England Inc. ("ISO") 2022 Operating and Capital Budgets

Budget Process

This memo provides an update to the NEPOOL Participants on the 2022 Budgets process. At its August 9, 2021 meeting, the NEPOOL Budget & Finance Subcommittee ("B&F") reviewed the ISO's proposed 2022 operating and capital budgets (collectively, the "Budgets"). Included with this memorandum is a presentation of the Budgets. The more detailed presentation provided to B&F can be found on the ISO's website at https://www.iso-ne.com/static-assets/documents/2021/07/6_isone_2022_proposed_op_cap_budget.pdf. The presentation included with this memorandum includes updates to the following slides, from the equivalent page in the more detailed B&F presentation: Slide 18 for 2021 Forecast Load value and mathematical calculation updates; Slides 23 and 24 to add capital project estimated completion dates; and slide 29 to add ERCOT 2020 financial data that just recently became available. The ISO has also presented the Budgets to the New England state agencies; following that presentation the state agencies submitted questions. The questions and the ISO's answers can be found on the ISO's website at https://www.iso-ne.com/static-assets/documents/2021/08/6_states_2022_budget_questions_08_2021.pdf.

For both meetings, the discussions covered the ISO's vision, strategic goals, and initiatives; key drivers of the proposed cost increase; the allocated resources in the 2022 budget to achieve the related objectives; and the 2022 budget risks. Additionally, we outlined factors contributing to the increase in the capital budget over the next several years and the estimated impact to our debt structure and borrowing needs. A few clarifying questions were asked during the B&F call, including the timing of headcount additions in 2022 and 2023, the status of the extreme weather events analysis, and whether the ISO has been subject to a ransomware attack.

In the discussion with the states questions were focused on metrics (i.e., how the ISO allocates resources, prioritizes work, and assesses the effectiveness of the markets). In response we explained that the ISO measures objectives on a per project basis (i.e., whether projects met cost, scope, and milestone goals) and, with respect to operations, by reviewing reliability and compliance requirements. We also referenced the Internal Market Monitor and External Market Monitor assessments regarding the effectiveness of the markets. Additionally, we noted that the ISO allocates resources and prioritizes work based on Commission requirements, stakeholder discussions, and business needs (e.g., the need to keep current on technology for cyber security and vendor support).

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The Participants Committee will be asked to vote on the proposed budgets at the October 7, 2021 meeting.

Proposed 2022 Budgets

The Budget assumptions, key drivers, and operating budget before depreciation remain consistent with the preliminary budgets presented to NEPOOL in June; however, the depreciation budget is $1.2 million higher than amounts in the preliminary budget due to refinement of timing and amounts of capital budget spending. The 2022 operating budget year-over-year increase before depreciation is $10.6 million or 5.9%; the increase, including depreciation is $10.3 million or 5.0%.

The budget reflects the resourcing needed to continue to make progress with the highest priority initiatives, as identified in the ISO work plan. Included in our corporate goals, and reflected in our budget, is the ISO's continued focus on innovation in support of the region's effort to transition to high levels of renewable and distributed resources while ensuring that the power system is reliable through the transition and preserving the ability of the market to attract new entry. The budget includes funding for: the integration of increasing levels of clean energy and distributed resources; efforts to address evolving cyber security threats given the ISO's high level of reliance on information technology; and attracting and retaining the talent to carry out this critical work and the ISO's mission.

Assessing resourcing needs, the ISO anticipates the need for approximately 21 full-time equivalent ("FTE") additions between 2022 and 2023. The 2022 budget includes the recruitment of 14 additional positions, with funding for 9 FTEs with onboarding expected to occur throughout the year. In 2023 the funding for a full year of all 14 of the 2022 positions plus the addition of 7 positions for 2023 is expected, bringing the two year total to 21. The additional 2022 positions include those for Market Development, System Planning, Information Technology Cyber Security and Power System Modeling, Legal, Advanced Technology Solutions, and Finance.

The capital budget is $32 million. Between 2022 and 2027 the capital budget is expected to increase by up to $7M over the $28M budget that has been in place for several years. The increased capital budget need is being driven by 4 primary drivers as follows: nGEM platform (which replaces the current market system); Major market and reliability related efforts; Cyber security; IT asset and infrastructure replacement.

I will be available during the meeting for any questions regarding the 2022 Budgets. Please also feel free to reach out to me after today with any additional comments or questions regarding the 2022 Budgets.

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SEPTEMBER 2, 2021

ISO New England Proposed 2022 Operating and Capital Budgets

NEPOOL Participants Committee Meeting

Robert Ludlow

VP, CHIEF FINANCIAL & COMPLIANCE OFFICER

Contents of Presentation

- The presentation includes:
  - 2022 Budget Introduction and Overview (Slides 3-6)
  - Strategic Planning Process Overview (Slides 7-12)
  - 2022 Budget Overview (Slides 13-16)
  - Summary 2022 Budget Information (Slides 17-19)
  - 2022 Operating Budget Risks (Slides 20-21)
  - Capital Budget Summary (Slides 22-25)
- The following appendices are also included for reference:
  - Appendix 1: Cyber Security and CIP Compliance History and Costs
  - Appendix 2: ISO/RTO Financial Comparison
  - Appendix 3: New England Wholesale Electricity Costs and Retail Electricity Rates

2022 BUDGET INTRODUCTION AND OVERVIEW

2022 Budget Review Process

- At both the June 1, 2021 meeting with the New England Conference of Public Utilities Commissioners (NECPUC), and the June 24, 2021 NEPOOL Participants Committee meeting, management presented and reviewed the preliminary operating and capital budgets for 2022
  - The 2022 operating budget, before depreciation, is consistent with amounts included in the preliminary budget presented in June, while the depreciation budget is $1,220,300 higher than amounts in the 2022 preliminary budget due to the refinement of timing and amounts of capital budget spending
- The budget reflects the resourcing needed to continue to make progress with the highest priority initiatives, as identified in the ISO work plan
- Included in our corporate goals, and reflected in our budget, is the ISO's continued focus on innovation in support of the region's effort to transition to high levels of renewable and distributed resources while ensuring that the power system is reliable through the transition and preserving the ability of the market to attract new entry
- The integration of increasing levels of clean energy and distributed resources; efforts to address evolving cyber security threats given the ISO's high level of reliance on information technology; and attracting and retaining the talent to carry out this critical work and the ISO's mission is reflected in the budget

2021 Budget Review Process *(cont.)*

- The ISO reviewed the 2022 proposed Operating and Capital Budgets:
  - With the NEPOOL Budget & Finance Subcommittee on August 9th; for further detail on ISO-NE's 2022 budget, please see the presentation provided to the NEPOOL Budget & Finance Subcommittee at the August 9, 2021 meeting; the presentation can be found at: https://www.iso-ne.com/static-assets/documents/2021/07/6_isone_2022_proposed_op_cap_budget.pdf
  - With the State Agencies on August 6th
    - State Agencies submitted questions on ISO-NE's proposed budget on August 13th
    - ISO-NE responded to State Agencies' questions on August 20th; the State Agencies questions and ISO-NE's responses can be found at: https://www.iso-ne.com/static-assets/documents/2021/08/6_states_2022_budget_questions_08_2021.pdf
    - State Agencies may submit comments regarding the proposed budget by September 10th
    - The ISO Board of Directors will review the budgets, stakeholder feedback, and State Agencies comments on September 22nd
    - ISO-NE responses to State Agencies' comments are due on or about September 29th
- The ISO will conduct additional meetings as requested

2021 Budget Review Process *(cont.)*

- The NEPOOL Participants Committee (NPC) will vote on the ISO-NE 2022 Budgets on October 7th
- The ISO Board of Directors will vote on the 2022 Budgets after the NPC meeting
- The ISO will file the 2022 Budgets with FERC on or about October 15th

STRATEGIC PLANNING PROCESS OVERVIEW

The Annual Process – Strategic Planning

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

ISO New England's Vision

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

Vision Statement:

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

Our Strategic Goals

The ISO ties its annual budget to resource requirements by Goals, Objectives, and Initiatives

ISO-NE Strategic Goals

- **Responsive Market Designs:** Improve the current market structure and continue to evolve and reposition the market design to accommodate the states' objectives and the transition to high levels of renewables and distributed resources. Maintain a robust fleet of balancing resources and preserve the ability of the market to attract new entry.
- **Progress and Innovation:** Evolve capabilities to support the grid as the region transitions to clean energy, including improved power system and market modeling. Support investments in transmission infrastructure to enable renewable energy. Facilitate the integration of distributed energy resources. Provide data and information-based services.
- **Operational Excellence**: Continuously improve operations and processes, with a focus on efficiency and effectiveness, business results, and continuity of operations.
- **Stakeholder Engagement:** Collaboratively understand and anticipate needs, demonstrate thought leadership through high quality analysis and communication, and nurture productive relationships with FERC, the states and market participants.
- **Attract, Develop, and Retain Talent:** Develop a sense of community around our Core Values, Mission, Vision, and Goals; prepare the workforce; recognize and reward employee's success and innovation; and honor diversity and promote inclusion.

Summary of 2022 Objectives

Goal 1: Responsive Market Designs

- Advance Energy Security and Additional Market Services to Support the Region's Transition to Clean Energy
- Address Impacts of Distributed Resources on Market Services

Goal 2: Progress and Innovation

- Enhance Modeling Capabilities for New Technologies and Distributed Resources to Keep Pace with the Evolving Power System
- Research and Develop Tools and Processes for Enhancing Real-Time Situational Awareness and Market Administration
- Future Grid/Transmission Studies
- Enhance Mitigation of Market Financial Risk

Goal 3: Operational Excellence

- Develop Scalable Technology Solutions to Address Evolving Cyber Security Threats, Effectiveness of Operations, Evolving Workplace Requirements, and Meet Reliability Metrics
- Continuously Improve Restoration Capabilities Through Cyber Security, Infrastructure, and Asset Replacement to Ensure Continuity of Operations
- Continually Update Technology, Software, Analytics, and Modeling Capabilities in a Structured Way to Support Operations
- Develop Business Efficiency Improvements

Summary of 2022 Objectives *(cont.)*

Goal 4: Stakeholder Engagement

- Affirm State and Stakeholder Risk-Tolerance and Readiness Regarding Extreme Weather Events
- Responding to Stakeholders, Educating and Ensuring Awareness of Impacts of Ongoing and Relevant Trends
- Communicating Potential Tariff Changes from Adoption of New Practices and Longer-Term (>10 year) Studies
- Reinforce ISO's Identity and Share Best Industry Practices with Industry and Region

Goal 5: Attract, Develop, and Retain Talent

- Launch Internal Communication Efforts to Familiarize ISO Employees with the Importance of the Organization's Mission, Vision, Core Values, and Strategic Goals

Goal 5: Attract, Develop, and Retain Talent (continued)

- Design, Implement, and Measure Training and Mentorship Solutions to Support the Development of Employees' Managerial, Leadership, Interpersonal, and Business Skills
- Assure the ISO's Culture is Supportive of Diversity and Inclusion by Running Unconscious Bias Training and Further Development of the Council for Diversity and Inclusion (CDI)
- Ensure use of Competitive Benefits and Compensation to Attract the Technical Skills and Talent the ISO Needs to Support the Requirements of a Transition to a Clean-Energy Future

2022 BUDGET OVERVIEW

2022 Budget Overview

- Assessing resourcing needs, the ISO anticipates the need for approximately 21 FTE additions between 2022 and 2023
  - Over the past 5 years full-time equivalent position funding has been kept flat with the ISO supplementing staffing needs with contract additions where practicable to augment staff and cover short-term needs
- The 2022 budget includes funding for 9 FTE(1) additions primarily to address the growing volume and workload for the integration of clean energy and distributed resources in the Market Development, Transmission Planning, Power System Modeling, and Legal areas; and for Cyber Security and Information Technology support

(1) The 2022 budget includes the recruitment of 14 additional positions, with funding for 9 full-time equivalents with onboarding expected to occur throughout the year. In 2023 the funding for a full year of all 14 of the 2022 positions plus the addition of 7 positions for 2023 is expected, bringing the two year total to 21 as noted above.

2022 Budget Overview *(cont.)*

- The operating budget includes an increase of $0.9M of contingency funding that will be used to target areas of importance to the region including Transmission Planning for Clean-Energy Transition, Resource Capacity Accreditation (Effective Load Carrying Capability (ELCC) analysis), cyber security needs, and Pathways to the Future Grid studies
  - ISO-NE's preliminary budget contemplated $1.2M in additional study work in the area of Market Development to address these targeted areas; however, when the planning phases of these efforts are completed later in 2021 and early 2022, and the required work and related resources are defined, these estimates will be firmed up; it is unpredictable as to the exact level of funding that will be required; the limited additional contingency allows a constrained level of flexibility to finance these initiatives

2022 Budget Overview *(cont.)*

- In summary, the 2022 operating budget year-over-year increase before depreciation is $10,605,000 or 5.9%; the increase, including depreciation is $10,277,400 or 5.0%
- The 2022 Capital Budget is $32 million
  - Between 2022 and 2027 the capital budget is expected to increase by up to $7M over the $28M budget that has been in place for several years
    - The increased capital budget need is being driven by 4 primary drivers as follows:
      - nGEM platform (which replaces the current market system)
      - Major market and reliability related efforts
      - Cyber security
      - IT asset and infrastructure replacement
    - The increased capital spending will result in higher interest expense costs and depreciation expense in future years as capital projects go into production and are included in budgets and rates
  - The 2022 capital budget of $32.0 million is provided with a list of projects, by strategic goal, that are currently chartered and on-going or in planning/conceptual design (See Slides 23-25)

Note: Throughout the presentation some schedules may appear inconsistent due to rounding of amounts.

SUMMARY 2022 BUDGET INFORMATION

Summary Budget Information

(Budget Amounts are in Millions)	2022	% Change	2021	% Change	2020	% Change	2019	% Change	2018	% Change	2017
Operating Budget Before Depreciation	$189.2	5.9%	$178.6	1.8%	$175.4	3.9%	$168.9	2.9%	$164.2	3.3%	$158.9
Capital Budget	32.0	14.3%	28.0	0.0%	28.0	0.0%	28.0	0.0%	28.0	0.0%	28.0
Total Cash Budget	**$221.2**	**7.1%**	**$206.6**	**1.6%**	**$203.4**	**3.3%**	**$196.9**	**2.5%**	**$192.2**	**2.8%**	**$186.9**
Operating Budget Before Depreciation	$189.2	5.9%	$178.6	1.8%	$175.4	3.9%	$168.9	2.9%	$164.2	3.3%	$158.9
Depreciation	26.0	(1.2)%	26.3	0.2%	26.3	(9.6)%	29.1	(6.3)%	31.0	(8.0)%	33.7
Revenue Requirement Before True-up	215.2	5.0%	205.0	1.6%	201.7	1.9%	198.0	1.5%	195.2	1.3%	192.7
True up	1.1		0.2		(2.9)		(9.3)		0.4		(0.4)
Revenue Requirement	**$216.3**	**5.5%**	**$205.1**	**3.2%**	**$198.8**	**5.4%**	**$188.7**	**(3.5)%**	**$195.5**	**1.7%**	**$192.3**
Forecast – TWhs (1)	**144.4**	**(2.0)%**	**147.4**	**1.0%**	**145.9**	**0.2%**	**145.6**	**2.5%**	**142.1**	**1.2%**	**140.3**
$/KWh Rate	**$0.00150**	**7.6%**	**$0.00139**	**2.1%**	**$0.00136**	**5.1%**	**$0.00130**	**(5.8%)**	**$0.00138**	**0.4%**	**$0.00137**
Average Monthly Consumer Cost (2)	**$1.12**		**$1.04**		**$1.02**		**$0.97**		**$1.03**		**$1.03**

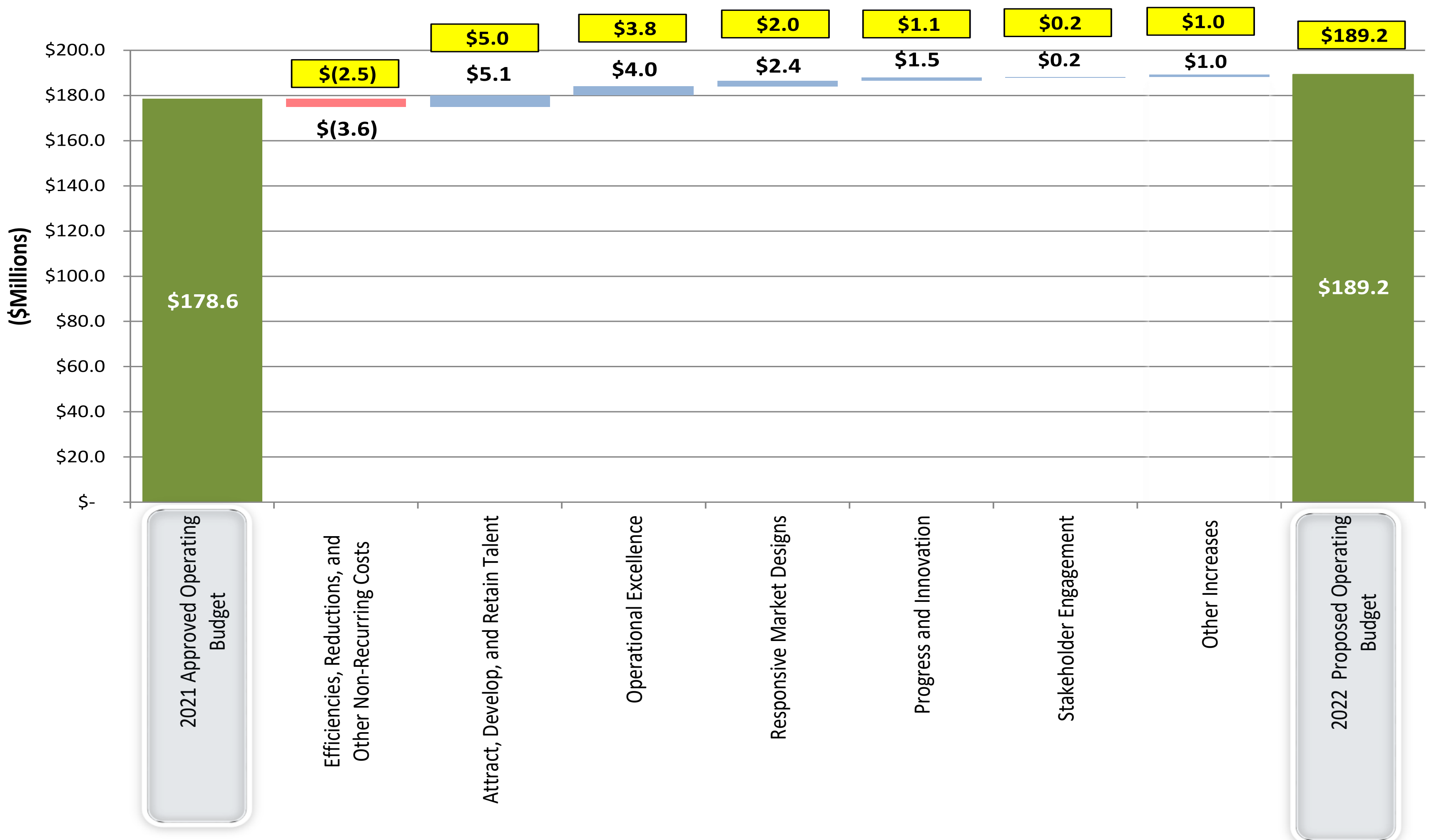
(1) 2022 Forecast based on May 2021 CELT Report (Schedule 1.5.2 - Net Annual Energy - Gross (without reductions)). All other years based on CELT Report for the applicable year, which can be found on www.iso-ne.com.

(2) Based on average consumption of 750 kWh per month.

Note: Throughout the presentation some schedules may appear inconsistent due to rounding of amounts.

2022 Budget Changes by Strategic Goal Proposed vs. Projected

(net increase of 5.9% (consistent with Projected Budget) over 2021)



Note: Items in yellow above represent the estimate that was included in the 2022 preliminary budget presented in June 2021.

2022 OPERATING BUDGET RISKS

2022 Operating Budget Risks

- Although ISO-NE spending has never exceeded budget, the risk exists that ISO-NE may have to incur additional expenditures during 2022; specific potential risks include:
  - Additional funding may be required to support the next phase of the pathway studies project, construct new models to study extreme weather and contingencies, conduct new studies and the integration of the penetration of variable resources and emerging technologies including long-range transmission planning
  - Information Technology software licensing and maintenance costs may require additional funding
  - Insurance policy renewals may be higher than increases estimated in the budget
  - Interest Rates may impact ISO-NE floating rates on tax-exempt debt, pension and post-retirement benefit plans liability costs, and interest income on settlement float balance
  - Legal costs from material litigation that may arise during the course of the year would pose a risk to ISO-NE's ability to operate within the approved budget
  - Federal and state policy directives/changing policies could result in additional cost associated with new requirements including multiple scenarios under a 2050 Transmission Study
  - Potential impact of workforce disruption due to continued uncertainty in remote versus on-site work

CAPITAL BUDGET SUMMARY

Capital Budget

2022 Expenditures

Goal: Responsive Market Designs

Project	2022 Budget	Total Project Cost	Estimated Completion Date	Project Stage
nGEM Market Clearing Engine Implementation (see Note 1)	$4.4M	$13.9M	03/23	In Development
nGEM Software Development Part II (see Note 1)	$2.7M	$4.8M	12/22	In Development
nGEM Hardware Phase II (see Note 1)	$3.0M	$3.0M	12/22	Planning/Conceptual Design
Minimum Offer Price Rule	$1.5M	$2.0M	12/23	Planning/Conceptual Design
Solar Do Not Exceed Dispatch	$0.5M	$0.6M	09/22	Planning/Conceptual Design
Total:	**$12.1M**			

Goal: Progress and Innovation

Project	2022 Budget	Total Project Cost	Estimated Completion Date	Project Stage
Internal Market Monitoring Data Analysis Phase III	$0.9M	$1.6M	12/22	In Development
Integrated Market Simulator Phase I	$0.4M	$1.5M	06/22	In Development
Replacement of Locational Marginal Price Monitor	$0.1M	$0.4M	04/22	In Development
Amazon Web Services (“AWS”) Cloud Foundation	$1.0M	$1.0M	04/22	Planning/Conceptual Design
Linear State Estimator	$0.5M	$0.7M	10/22	Planning/Conceptual Design
External Website Migration to Cloud	$0.4M	$0.4M	10/22	Planning/Conceptual Design
Total Transfer Capability Calculator Redesign w/G2 Replacement	$0.3M	$0.4M	04/22	Planning/Conceptual Design
Forecast Enhancements	$0.2M	$0.2M	06/22	Planning/Conceptual Design
Total:	**$3.8M**			

Note 1: nGEM related projects will advance multiple goals including Responsive Market Designs, Progress and Innovation, and Operational Excellence. For purposes of this presentation, nGEM projects have been grouped under the Responsive Market Designs strategic goal.

Capital Budget

2022 Expenditures Cont'd

- Goal: Operational Excellence

Project	2022 Budget	Total Project Cost	Estimated Completion Date	Project Stage
Forward Capacity Tracking System Infrastructure Conversion Part III	$2.9M	$3.2M	12/22	In Development
Security Info. and Event Mgt. Log Monitoring Replacement	$0.3M	$2.9M	07/22	In Development
Forward Capacity Market Cost Allocation & Accelerated Billing	$0.3M	$1.1M	05/22	In Development
TranSMART Technical Architecture Update	$0.3M	$0.8M	06/22	In Development
Cyber Security Improvements	$2.0M	$2.0M	12/22	Planning/Conceptual Design
2022 Issue Resolution Projects	$1.5M	$1.5M	12/22	Planning/Conceptual Design
CIP Electronic Security Perimeter Redesign Phase II	$1.0M	$1.0M	12/22	Planning/Conceptual Design
Enterprise Application Integration Phase III	$0.5M	$0.5M	11/22	Planning/Conceptual Design
Windows Server 2019R2 Deployment	$0.4M	$0.8M	06/23	Planning/Conceptual Design
Identity and Access Management Phase III	$0.4M	$0.4M	12/22	Planning/Conceptual Design
Email List Server Technology Refresh	$0.3M	$0.4M	06/22	Planning/Conceptual Design
Non-Project Capital Expenditures	$3.0M			Planning/Conceptual Design
Total:	**$12.9M**			

Capital Budget

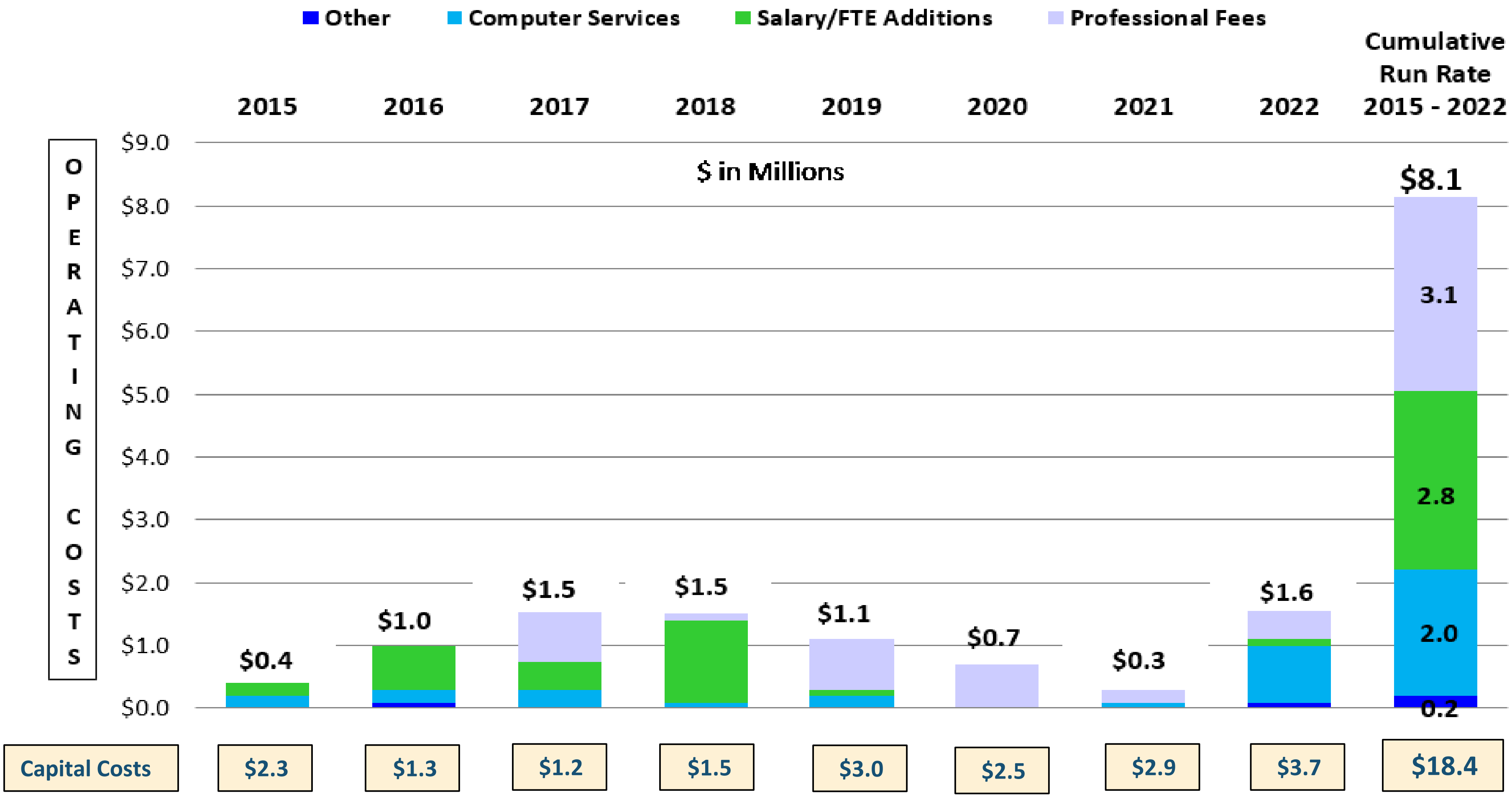
2022 Expenditures Summary

- 2022 Capital Budget Expenditure Summary

Allocation Category		2022 Budget
Goal: Responsive Market Designs		$12.1M
Goal: Progress and Innovation		$ 3.8M
Goal: Operational Excellence		$12.9M
Other Emerging Work		$ 2.7M
Capital Interest		$ 0.5M
	Total:	**$32.0M**

APPENDIX 1: CYBER SECURITY AND CIP COMPLIANCE HISTORY AND COSTS

Cyber Security and CIP Compliance Annual Capital and Incremental Operating Costs 2015-2022



Above amounts represent cumulative annual costs for cyber security that have been added in the 2015 through 2022 budgets and are on-going and included in the 2022 proposed budget. An additional $1.2 million of incremental non-recurring cyber security costs were incurred from 2015 through 2021 that are not included above.

APPENDIX 2: ISO/RTO FINANCIAL COMPARISON

Financial Results Summary

ISO/RTO Financial Summary - 2020 Actual Results

Operating Expense and Capital Expenditures for Calendar Year 2020, and Outstanding Debt as of December 31, 2020 (1)

(Amounts in Millions)

	ISO-NE (2)	NYISO	CAISO	IESO (3)	PJM	MISO	SPP	ERCOT
Operating Expense - 2020	$ 195.6	$ 202.7	$ 216.1	$ 227.0	$ 359.0	$ 373.9	$ 206.3	$ 211.7
Less: Amortization & Depreciation	(24.8)	(21.9)	(26.2)	(23.1)	(35.5)	(34.6)	(18.5)	(30.1)
Regulatory Fees	(6.4)	(14.2)	-	-	(65.3)	(53.1)	(22.3)	(19.4)
Grant Expenses	-	-	-	-	-	-	-	-
Net Operating Expense - 2020	$ 164.4	$ 166.5	$ 189.9	$ 204.0	$ 258.2	$ 286.3	$ 165.5	$ 162.2
Other Financial Data								
Capital Expenditures for 2020	$ 26.3	$ 17.3	$ 22.1	$ 56.3	$ 39.9	$ 38.9	$ 12.8	$ 33.5
Outstanding Debt as of 12/31/20	$ 96.0	$ 94.9	$ 169.4	$ 120.0	$ 13.7	$ 274.3	$ 182.1	$ 47.0
Actual full-time equivalent headcount as of 12/31/20	577.5	564.0	642.0	769.0	724.0	965.0	636.0	774.0

(1) Applicable amounts were taken from each entity's 2020 audited financial statements.

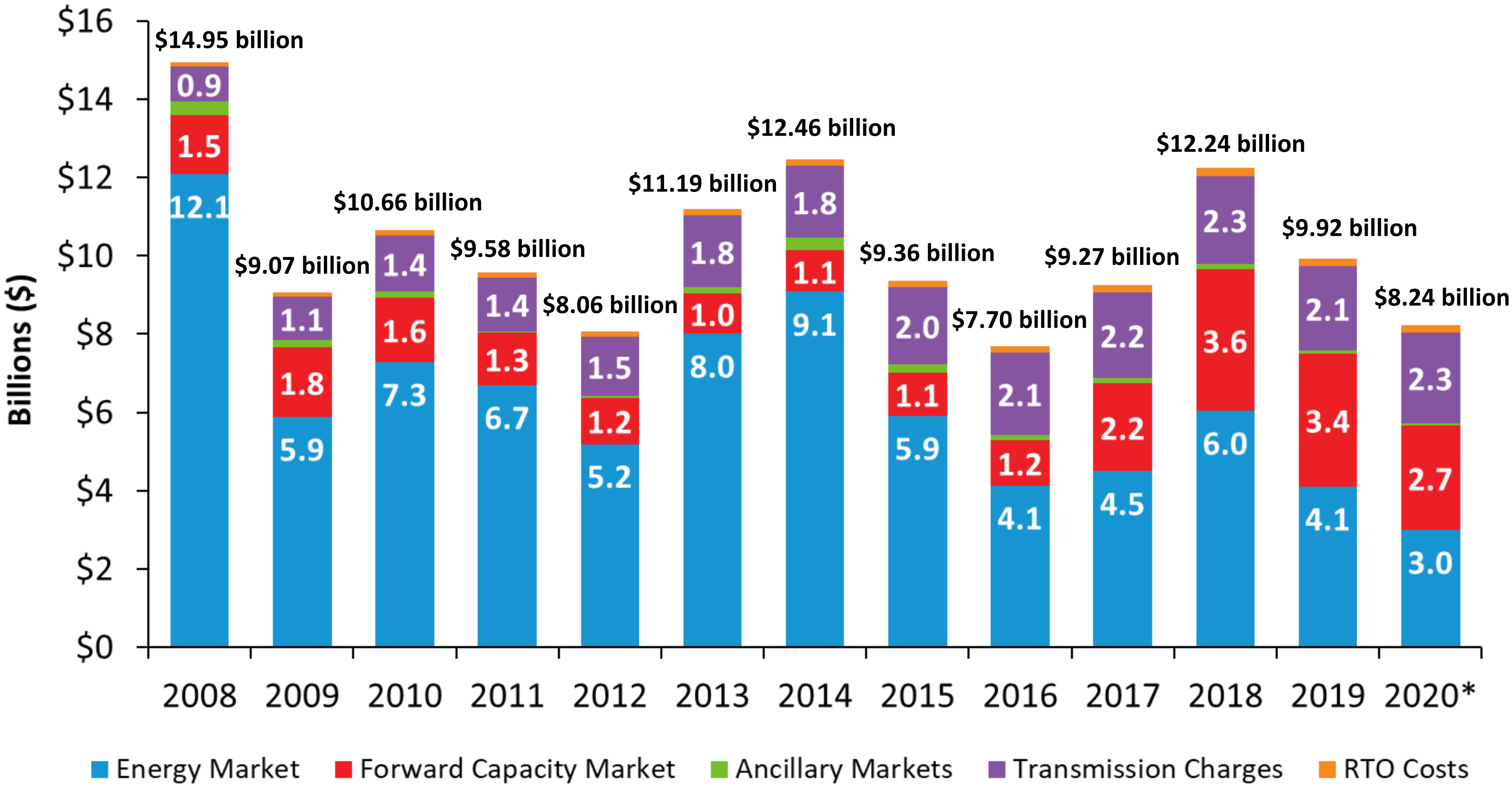
(2) ISO-NE Amortization & Depreciation and Capital Expenditures are presented on a cash-flow basis

(3) Amounts are in Canadian dollars

APPENDIX 3: NEW ENGLAND WHOLESALE ELECTRICITY COSTS AND RETAIL ELECTRICITY RATES

New England Wholesale Electricity Costs

Annual wholesale electricity costs have ranged from $7.7 billion to $15 billion



Source: *2020 Report of the Consumer Liaison Group*; *2020 data is preliminary and subject to resettlement
Note: Forward Capacity Market values shown are based on auctions held roughly three years prior to each calendar year.

New England Wholesale Electricity Costs[a]

	2016		2017		2018		2019		2020*	
	$ Mil.	¢/kWh	$ Mil.	¢/kWh	$ Mil.	¢/kWh	$ Mil.	¢/kWh	$ Mil.	¢/kWh
Wholesale Market Costs										
Energy (LMPs)[b]	$4,130	3.2	$4,498	3.5	$6,041	4.7	$4,105	3.3	$2,996	2.4
Ancillaries[c]	$146	0.1	$132	0.1	$147	0.1	$83	0.1	$62	0.1
Capacity[d]	$1,160	0.9	$2,245	1.8	$3,606	2.8	$3,401	2.7	$2,662	2.2
Subtotal	*$5,437*	*4.2*	*$6,875*	*5.4*	*$9,794*	*7.6*	*$7,589*	*6.0*	$5,720	4.7
Transmission charges[e]	$2,081	1.6	$2,199	1.7	$2,250	1.7	$2,146	1.7	$2,331	1.9
RTO costs[f]	$180	0.1	$193	0.2	$196	0.2	$184	0.1	$191	0.2
Total	**$7,698**	**5.9**	**$9,267**	**7.3**	**$12,240**	**9.4**	**$9,918**	**7.9**	**$8,242**	**6.7**

(a) Average annual costs are based on the 12 months beginning January 1 and ending December 31. Costs in millions = the dollar value of the costs to New England wholesale market load servers for ISO-administered services. Cents/kWh = the value derived by dividing the dollar value (indicated above) by the real-time load obligation. These values are presented for illustrative purposes only and do not reflect actual charge methodologies. ***The wholesale values for 2020 are preliminary and subject to resettlement.**

(b) Energy values are derived from wholesale market pricing and represent the results of the Day-Ahead Energy Market plus deviations from the Day-Ahead Energy Market reflected in the Real-Time Energy Market.

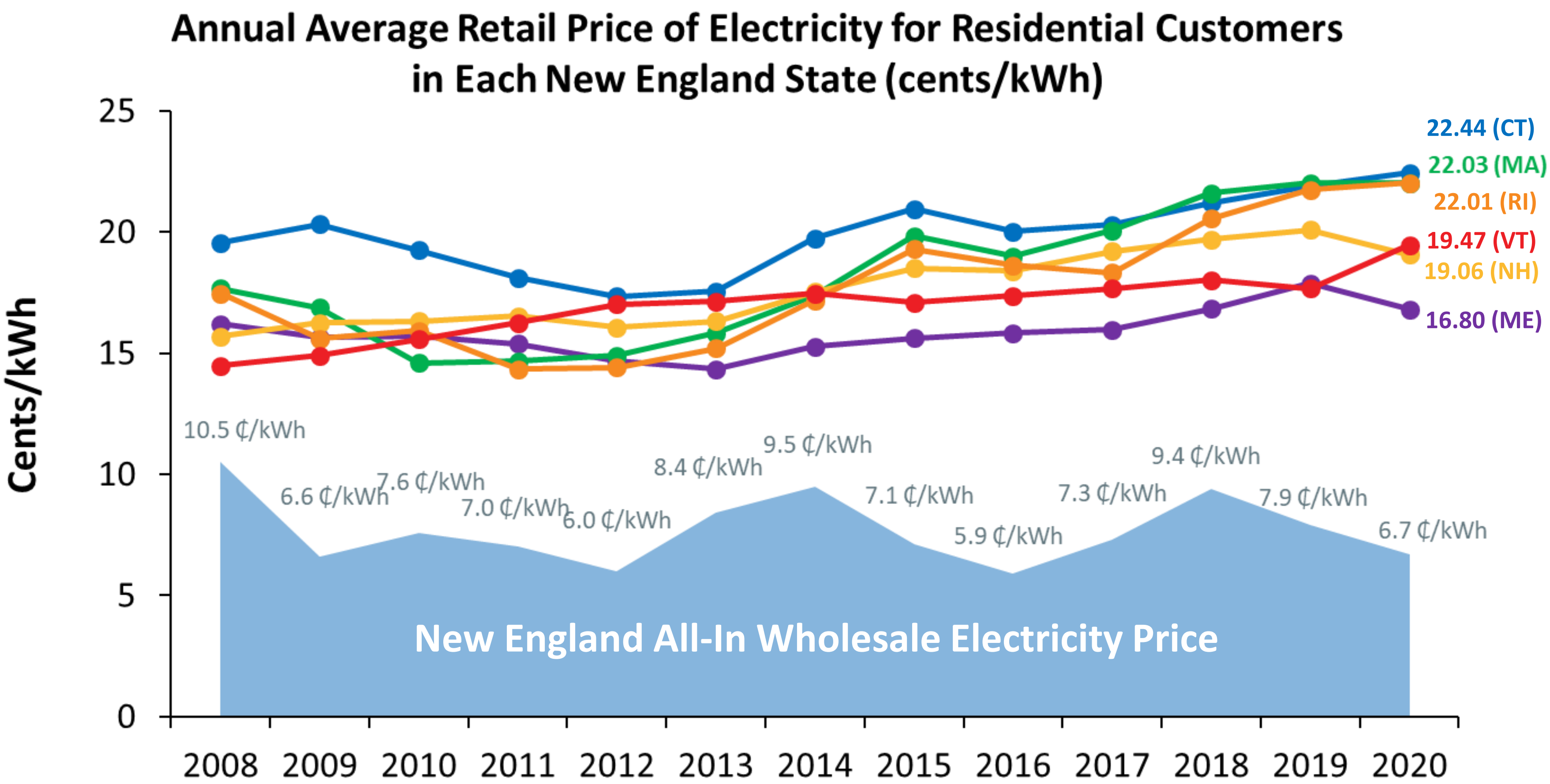
(c) Ancillaries include first- and second-contingency Net Commitment-Period Compensation (NCPC), forward reserves, real-time reserves, regulation service, and a reduction for the Marginal Loss Revenue Fund.

(d) Capacity charges are those associated with the Forward Capacity Market (FCM).

(e) Transmission charges reflect the collection of transmission owners' revenue requirements and tariff-based reliability services, including black-start capability, voltage support, and FCM reliability.

(f) RTO costs are the costs to run and operate ISO New England and are based on actual collections, as determined under Section IV of the *ISO New England Inc. Transmission, Markets, and Services Tariff*.

Retail Electricity Prices Follow Wholesale Prices, But Are Also Influenced by Individual State Policies



Source: U.S. Energy Information Administration, *Electric Power Monthly*, Average Retail Price of Electricity to Ultimate Customers by End-Use Sector, by State (Annual); *2020 Report of the Consumer Liaison Group*, the New England all-in wholesale electricity price is derived by dividing total wholesale electricity costs by real-time load obligation (presented for illustrative purposes; does not reflect actual charge methodologies)

State Agencies' Questions to ISO-NE regarding 2022 Budget

1) Please provide the latest copy of ISO-NE's FERC Form 1 to each state agency representative.

   Electronic pdf version is attached.

2) Please provide the most recent copy of ISO-NE's Form 990 to each state agency representative.

   Electronic pdf version is attached.

3) Flexibility. Discuss ISO-NE ability to take on additional assignments within a budget year. Do certain areas of ISO-NE's operations suffer when unexpected tasks arise? Does ISO-NE need additional flexibility to handle unexpected work? Please explain.

   Each year, ISO-NE develops an annual work plan (published in the fall and updated in the spring), which outlines major priorities and activities for the year that are designed to improve upon existing ISO-NE systems, practices, and services to New England. The work plan is a result of ISO-NE planning and engagement with stakeholders; ISO-NE seeks stakeholder input on its work plan by sharing and discussing it with the New England Power Pool ("NEPOOL") Participants Committee and representatives of the New England states through the New England Conference of Public Utilities Commissioners ("NECPUC") and the New England States Committee on Electricity ("NESCOE"). Although the work plan specifies priorities and activities, ISO-NE necessarily maintains some flexibility to take on additional assignments or reprioritize previously identified initiatives. ISO-NE also prepares a rolling six-quarter forecast so as new information becomes available (regarding cost, resources, or other factors) or there is a shift in priorities, ISO-NE is able to pivot to that work and apply resources accordingly. Within a budget year, ISO-NE's flexibility is dependent on two factors: availability of budget funds and availability of internal (and external) resources.

   To ensure ISO-NE has sufficient funding to allow for flexibility and to address unexpected needs, the ISO-NE operating budget contains two line items: (i) the CEO Emerging Work Allowance ($1.1 million in 2021), and (ii) the Board Contingency ($700,000 in 2021). Inclusion of these contingency amounts provides ISO-NE with sufficient flexibility to address unforeseen needs. The CEO Emerging Work Allowance covers new or deferred activities and initiatives that emerge or become priorities during the year and requires approval from both the CEO and CFO. The Board Contingency provides a funding source of last resort and approval for use must be obtained from ISO-NE's Board of Directors. Notably, ISO-NE is seeking to increase the CEO Emerging Work Allowance for the budget year 2022 to allow for increased flexibility to address areas of importance to the region, including transmission planning for a clean-energy transition, resource capacity accreditation, cyber security needs, and Pathways to the Future grid studies. (See Slides 14, 52, 54, and 91, of the "ISO New England Proposed 2022 Operating and Capital Budgets" presentation (the "Budget Presentation") presented to the states on August 6, 2021).

Within the capital budget, ISO-NE works within the approved budget for any given capital year and, to the extent necessary, will reprioritize projects based on stakeholder feedback and internal resources. On a quarterly basis, ISO-NE reviews updates to the capital budget at meetings of the NEPOOL Budget and Finance Subcommittee and then files these updates with the Federal Energy Regulatory Commission ("FERC").

ISO-NE develops each proposed budget (for the upcoming year) to include adequate funds to support ISO-NE's mission which is aligned with the vision to harness the power of competition and advanced technologies to reliably plan and operate the grid as the region transitions to clean energy. ISO-NE will always prioritize core functions over emerging work, to ensure core operations do not suffer. Unexpected tasks will have to be considered within the context of the new and emerging initiatives already underway in ISO-NE's work plan, and be prioritized according to the relative importance of the unexpected task as compared to those already in the work plan.

As reflected by the increases in the 2022 proposed operating budget, resource allocation has become challenging as ISO-NE's workload has increased to address the highest priority initiatives as determined by FERC and discussion with ISO-NE's stakeholders. Working within ISO-NE's annual budget involves careful planning to ensure the company has the adequate internal resources (i.e., highly qualified personnel with specialized skills) to support its core functions and the aforementioned emerging work. This involves monitoring and managing full-time equivalent positions (and when new or additional positions become necessary) and ISO-NE's turnover rate (considering the costs of recruiting, relocation, development time, and the disruption of workflow).

4) Metrics. Please identify the metrics that ISO-NE uses to determine its performance and progress regarding:

   a) System reliability;

      ISO-NE employs various metrics to measure system reliability performance and progress. Among these are transmission equipment outage coordination metrics, which are documented in an annual public report, the ISO New England Transmission Equipment Outage report; this report is available on ISO-NE's website at https://www.iso-ne.com/markets-operations/transmission-operations-services/transmission-outage-scheduling/. Additionally, the Transmission Outage Coordination Working Group ("TOCWG") annually reviews the trends, performance, and challenges of the outage-coordination process, and proposes new goals for transmission outage-coordination metrics for the upcoming year to improve outage coordination and performance. The metrics assess, among other things, accuracy of ISO-NE's estimation of congestion cost impacts and inputs used in such estimation; long-term impacts on ISO-NE's rescheduling of transmission-outage requests; and the provision of information to the Participating Transmission Owners ("PTOs") to facilitate their identification of opportunities to improve outage coordination, reduce congestion costs, or increase operational flexibility. The TOCWG-set metrics tracked over the past three years (2018-2020) included: a long-term planning metric to measure the successful submittal of outages into the long-term outage process that could have an impact on economic dispatch and system reliability; a 90-day metric to measure the submittal of requests for outages that could have an impact more than 90 days before the planned outage date; a planned outage goal to improve coordination of all planned transmission outages; and an outage cancellation goal to improve timely notifications to ISO-NE for cancelling a transmission equipment outage by a specified time. Metrics that tracked outage coordination performance over the past three years consistently identified areas of continued success and improvement, as well as areas that may require improvements (which are then incorporated into action plans for effecting such identified improvements).

ISO-NE also tracks a number of compliance requirements set in the North American Electric Reliability Corporation ("NERC") Reliability Standards to measure system reliability performance and progress. These include a metric regarding the Inter-area Operating Standard that is based on a count of Interconnection Reliability Operating Limit ("IROL") exceedances and time to clear above defined time thresholds. The objective is for ISO-NE not to exceed an IROL for more than thirty minutes; past exceedances have been of short duration, demonstrating the ability to act quickly. ISO-NE also tracks system regulating metrics, such as NERC balancing standards which measure how effectively the region's supply and demand balance assists in maintaining interconnection frequency; Balancing Authority Area Control Error ("ACE") Limit compliance, which measures how well the region's supply and demand balance assists in maintaining the ACE limit; and metrics that measure ISO-NE's ability to activate operating reserves to restore its ACE following large resource losses, such as the Disturbance Control Standard. Over the past three years, ISO-NE has consistently met the defined thresholds, indicating operation of the system in compliance with the standards.

Additional metrics on system reliability performance are reflected in the monthly reports of ISO-NE's Executive Vice President and Chief Operating Officer to the NEPOOL Participants Committee, which are available on ISO-NE's website at: https://www.iso-ne.com/committees/participants/participants-committee/?document-type=COO%20Reports%20to%20the%20Participants%20Committee&load.more=2. An operational metric reflected in these reports is accuracy in load forecasting for all hours in the day and the peak hour of the day. On average, ISO-NE has met its load forecast accuracy objectives over the past three years, but 2020 was particularly challenging given the COVID-19 pandemic. ISO-NE forecasters, however, have continued to closely monitor load curve trends and retrain the models as the economy reopens, which has enabled ISO-NE to meet its load forecasting goals in recent months.

b) The wholesale markets (capacity, energy, and ancillary);

ISO-NE's Internal Market Monitor ("IMM") publishes quarterly and annual markets reports that assess the state of competition in the wholesale electricity markets operated by ISO-NE. Each annual markets report covers ISO-NE's most recent operating year and addresses the development, operation, and performance of the wholesale electricity markets administered by ISO-NE and presents an assessment of each market based on market data, performance criteria, and independent studies. For the past three years

(2018-2020), the IMM has found the ISO-NE capacity, energy, and ancillary services markets performed well and exhibited competitive outcomes.

Additionally, ISO-NE's External Market Monitor ("EMM"), Potomac Economics, publishes an Annual Assessment of the Electricity Markets in New England. This report provides a summary of market outcomes in the wholesale electricity markets designed and administered by ISO-NE, including the EMM's findings on the competitive performance and operational efficiency of the markets. For the past three years (2018-2020), the EMM has found that ISO-NE's wholesale electricity markets performed competitively; that market power concerns have diminished in Boston and New England; and the markets performed with little evidence of significant market power abuses or manipulation.

The past three IMM annual market reports are available at: https://www.iso-ne.com/markets-operations/market-monitoring-mitigation/internal-monitor

The past three EMM annual assessment reports are available at: https://www.iso-ne.com/markets-operations/market-monitoring-mitigation/external-monitor

c) Operational efficiency and effectiveness;

ISO-NE's operational performance is determined using goals that are set in advance by the Board of Directors. These goals are objective and measurable (on a monthly and annual basis) and represent organizational goals for operational reliability, efficient and competitive markets, budget performance, and support of stakeholder processes. The metrics regarding operational reliability include measuring compliance with NERC standards; cyber security audits and reporting; and forecasting and study preparation. The metrics regarding efficient and competitive markets include measures of Forward Capacity Market milestones, outage requests, and other market initiatives. The metrics regarding budget performance and the stakeholder process include measures of budget accuracy, information technology systems, employee training requirements, and the NEPOOL technical committee process.

The performance against these metrics is measured and reported to senior management on a monthly basis and is regularly published internally. Each individual goal has a target performance and is scored according to defined metrics, such as accuracy, completion, number of events or violations, etc. The scores are then compiled into an annual performance score. The calculation of each metric is verified by ISO-NE's internal auditors and the Board of Directors assigns a final score to the achievement of the annual goals.

d) Cyber security;

ISO-NE monitors its cyber security posture from several different perspectives. The following summarizes the metrics used and the general results.

ISO-NE's cyber security controls are modeled on the National Institute of Standards and Technology ("NIST") Framework for Improving Critical Infrastructure Cybersecurity, and the NERC Critical Infrastructure Protection ("CIP") controls. On a monthly basis, ISO-NE senior management reviews ISO-NE's cyber security performance against the NIST "Framework Core" which "is a set of cyber security activities, desired outcomes, and applicable references that are common across critical infrastructure sectors…[and] consists of five concurrent and continuous Functions – Identify, Protect, Detect, Respond, Recover." Review of these functions provides a "high-level, strategic view of the lifecycle of an organization's management of cyber security risk." Management's monthly review has indicated that ISO-NE's cyber security controls are functioning adequately and appropriately. The NIST framework is available at: https://nvlpubs.nist.gov/nistpubs/CSWP/NIST.CSWP.04162018.pdf.

Additionally, ISO-NE's Internal Audit Department actively reviews ISO-NE's processes and systems and maintains a particular focus on cyber security risks, including internal cyber security risks and third party risks. Each audit produces a set of recommendations for management regarding the subject of such audit, and management implements these recommendations as appropriate. Typically, audits regarding cyber security risks have indicated ISO-NE has an adequate cyber security posture and in some instances, maintains above-average cyber security controls. Finally, ISO-NE has procured various external cyber security reviews and audits that have confirmed ISO-NE has a solid cyber security foundation.

e) Incorporating state policy goals; and

State policies and goals are incorporated into ISO-NE's system planning processes, market design, and system operations in various ways. ISO-NE tracks the New England states' policy developments as they relate to the electric sector and shares this information with the appropriate staff for consideration in various aspects of system planning, operations, and market development. As examples, five of the six states have overarching greenhouse gas emissions reduction goals and various policies to help achieve those goals, and each of the six states has a form of Renewable Portfolio Standard (RPS) or Renewable Energy Standard (RES) and associated incentive programs; ISO-NE reflects these state-specified metrics into its annual regional system planning process. Similarly, ISO-NE tracks state energy efficiency goals and program spending and photovoltaic resource development, and incorporates this data in its annual and ten-year forecasts. These state policies have impacts on both ISO-NE system planning studies and procurements through the region's Forward Capacity Market. As a response to emerging state policy goals, in 2020, ISO-NE also began forecasting the electrification of transportation and heating.

As ISO-NE plans and studies the transmission system, it approaches future transmission planning that is responsive to state and local policies (and federal policies) using a unique process that is governed by direct state feedback based upon their own policy analysis. ISO-NE also develops and finalizes its biennial Regional System Plan in a way that reflects state policies and provides opportunities for the states and stakeholders to provide direct feedback on the report. In addition, ISO-NE works closely with states and distribution utilities on the interconnection process for distributed resources.

In grid operations, ISO-NE has monitored state policy goals as inputs to regional wind and solar forecasting, tracking, and dispatch procedures. The region's wholesale market development and design are continually influenced by state policy goals, such as plans to incorporate new ancillary services that support greater amounts of variable and distributed resources, and other flexible products. As market design proposals flow through the NEPOOL stakeholder process, the states have opportunities to engage ISO-NE and stakeholders directly, and provide feedback in that process.

In market design, ISO-NE has developed rules that allow for market participation of state-policy resources such as energy efficiency, demand response, and emerging technologies. ISO-NE implemented rules to allow for participation of state-sponsored resources in the capacity market and recently announced additional market rule changes to facilitate further opportunities for participation.

The states' efforts to achieve a decarbonized electricity sector and a clean energy future shape many aspects of ISO-NE's annual budget, work plan, and strategic goals. In annual strategic plan discussions, ISO-NE assesses state policy activity and industry trends to determine if any adjustments to priorities and projects are necessary.

f) Transmission system interconnections and upgrades.

In 2020, ISO-NE began publishing quarterly performance metrics for Interconnection Requests in compliance with FERC's Order No. 845. *ISO New England's Performance Metrics for Large Generating Facility Interconnection Requests in Compliance with Order No. 845* are publicly available publicly on ISO-NE's OASIS site at: http://www.oasis.oati.com/woa/docs/ISNE/ISNEdocs/Order845GItracker.pdf. The performance metrics track the processing time for each Interconnection Study – Feasibility Study, System Impact Study, and Facility Study – that is performed under the Large Generator Interconnection Procedures in Schedule 22 of the Open Access Transmission Tariff, as well as statistics on Interconnection Requests withdrawn from the interconnection queue at different phases of the interconnection process. More specifically, the metrics track the number of completed Interconnection Studies and the number of those studies for which ISO-NE exceeded the deadlines specified in the tariff for completion of the studies (without accounting for allowable Reasonable Efforts). Interconnection Studies are performed for Interconnection Requests to identify the transmission system upgrades necessary to facilitate the interconnection of the resources proposed in the requests to the New England system.

Additionally, ISO-NE submits informational quarterly reports to FERC whenever it exceeds the deadline for completing Interconnection Studies for more than 25% of any study for two consecutive calendar quarters. These informational reports are posted on ISO-NE's website, and the latest one is available at: https://www.iso-ne.com/static-assets/documents/2021/08/public_qtrly_interconnec_metrics_rpt_q2_2021.pdf. In addition to identifying the Interconnection Studies for which ISO-NE exceeded the completion deadlines, the informational reports provide the reasons for each Interconnection Study delay and any steps taken to remedy the specific issues and, if applicable, prevent such delays in the future.

Since ISO-NE began calculating and reporting on the Interconnection Study timeline metrics, it has observed continuous improvements for the Feasibility Study timeline. The improvements may be attributable to the reduced scope of that study that ISO-NE also implemented in 2020. Conversely, the reporting shows the time to complete System Impact Studies has increased, largely due to the complexity and length of the studies for previously-queued projects, which, correspondingly, delay the start of subsequent studies. These studies included the analysis of large offshore wind farms and inverter-based resources, which generally require complex analysis, and the design of complex upgrades such as dynamic reactive devices.

For each identified metric, provide a description of the metric, how ISO-NE uses the metric, and what the metric indicates regarding ISO-NE performance and progress over the last three years.

5) Stakeholder Feedback. For the past three years, what are the main areas of stakeholder feedback/concerns provided to ISO-NE? For each area, provide the nature of the feedback/concern, how it was brought to ISO-NE's attention, and the steps ISO-NE is taking to address the feedback/concern.

ISO-NE has created and supports extensive forums for receiving and responding to state and stakeholder feedback. Feedback from the states and stakeholders is continuous, diverse, and varies widely. ISO-NE receives feedback on specific projects, such as market designs or planning procedure proposals; requests for additional information; and requests to study or undertake further development on specific topics. As noted in the answer to Question 3 above, ISO-NE also identifies and discusses regional priorities and projects through the annual work plan discussions.

ISO-NE obtains and responds to feedback through Participant Support and Solutions platforms (AskISO), board sector meetings, staff sector meetings, NEPOOL committee meetings, and planning committee meetings (e.g., Planning Advisory Committee, Environmental Advisory Group, Distributed Generation Forecast Working Group, and Energy Efficiency Forecast Working Group). In addition to NEPOOL members, state and consumer representatives are invited to attend and participate in these meetings. ISO-NE also initiates and responds to individual meeting requests by companies and organizations, and through outreach to and by individual ISO-NE employees on projects or areas of interest. Finally, ISO-NE utilizes stakeholder surveys to get annual feedback on its performance.

ISO-NE also holds monthly meetings with state organizations focused on electricity matters (e.g., NECPUC and NESCOE). Members of senior staff and the board conduct regular outreach meetings in every state, and ISO-NE staff present and respond to inquiries at numerous legislative committees. Furthermore, ISO-NE responds to numerous other speaking engagements where it provides requested information and context about its vision, mission, and proposed plans. At these forums, ISO-NE is open to and responsive to a multitude of questions. Examples of such educational forums include the Consumer Liaison Group and a wide range of state, regional, national, and global government and industry meetings and conferences. ISO-NE also conducts training on a wide variety of issues as requested and needed for stakeholders to understand and engage in business with ISO-NE; this includes annual training exclusively for government officials and staff.

In addition to the formal meeting process, concerns and requests are often provided directly to ISO-NE through its participant support system (AskISO), which serves as a first line of responsiveness to inquiries and feedback about current rules and processes. ISO-NE receives approximately 9,000 AskISO inquiries a year. For the past several years, the top three topics of questions (by volume) have been questions related to non-Forward Capacity Market information (e.g., eMarket, Internal Bilaterals, Regulation Market, Continuous Storage Facilities); questions related to the Forward Capacity Market and qualification information; and questions related to various data requests (e.g., how to interpret data, suggestions for data, and how to locate data).

Finally, the information and data ISO-NE provides on its website, through ISO Express, and the ISO mobile app are made available to be responsive to the states and stakeholders and to transparently provide access to the vast, non-commercial, information at its disposal.

6) Stakeholder Feedback. What steps is ISO-NE taking to increase stakeholder feedback? What steps is ISO-NE taking to increase its responsiveness to stakeholder feedback?

ISO-NE continues to expand the market and operational data and analysis that is available on ISO-NE's website, ISO Express (data portal), and the ISO mobile app in response to stakeholder feedback and interests. ISO-NE continually creates and provides up-to-date forums to respond to requests for information and to help ensure stakeholders have an opportunity for additional understanding and context of issues through trainings, technical sessions, and stakeholder sector meetings. Written and verbal requests received in various forums (e.g., committee discussions, informal discussions, and work plan meetings) are considered and assessed by subject matter experts in the course of developing new proposals.

ISO-NE has undertaken studies (e.g., pathways, future grid reliability studies, expanded transmission planning, and lessons learned studies) that are directly responsive to stakeholder feedback and ISO-NE has incorporated consequential changes as a result of this feedback.

Ultimately, ISO-NE has constrained resources and cannot attend equally to all requests for service. That is why it is important to develop, and periodically refresh, a work plan that prioritizes the various initiatives. The ISO-NE work plan is developed with the input of all stakeholders and is reviewed at least twice a year with NEPOOL and NESCOE.

New England States
Committee on Electricity

2022 Budget Presentation

NEPOOL Budget & Finance Subcommittee

August 9, 2021

Background: Budget Review

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

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

Background: Policy Priorities

Term Sheet Provision Governing Identification of Policy Priorities:

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

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

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

Projected Policy Priorities

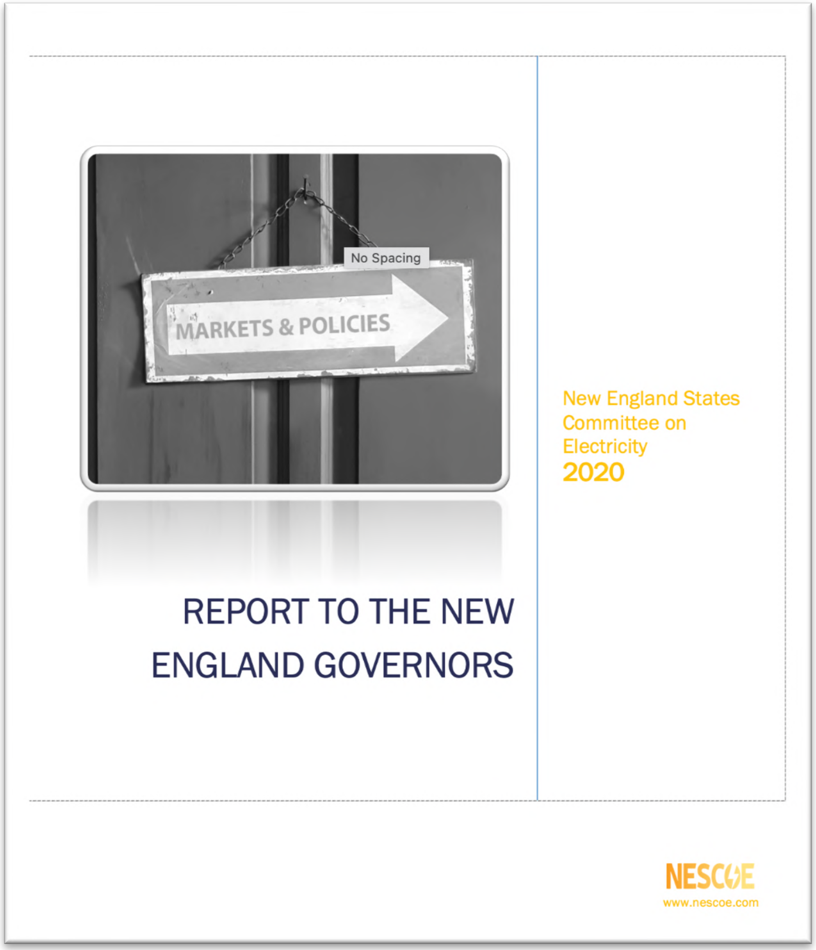
- ✓ NESCOE provided to the Governors the ***2020 Annual Report to New England Governors***

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

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

Report in "Resource Center"

www.nescoe.com



Projected Policy Priorities, update

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

NESCOE Organization & Misc.

Employees

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

Office Space

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

Other Organization Matters

Technical Consultants

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

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

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

Legal Counsel

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

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

5-Year Pro Forma

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

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

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

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

5-Year Pro Forma, for reference

NESCOE
PRO FORMA BUDGET 2018-2022*

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

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

2022 Proposed Budget

NESCOE Pro Forma Budget
Proposed 2022

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

2020 & 2021 Spending & Implications for 2022

Unspent funds in any year credited toward future year

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

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

2022 Projected Billing Rate

With thanks to ISO-NE for calculations -

2022 Budget:	$2,485,156
Less 2020 True Up:	($781,042)
Total Revenue Recovery:	$1,704,114
Divided by Total Network Load:	217,262,589

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

2022 Schedule 5 Estimated **Rate $0.00784 per kW-month**

Thank you.

Questions?

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Paul Belval and Samantha Regan, NEPOOL Counsel

DATE: August 26, 2021

RE: Request by Stored Solar for Waiver of GIS Operating Rules and GIS Agreement

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At the September 2, 2021 Participants Committee meeting, Stored Solar J&WE, LLC ("Stored Solar") will ask the Participants Committee to waive certain NEPOOL Generation Information System ("GIS") Operating Rules ("Rules") and sections of the Amended and Restated Generation Information System Administration Agreement dated as of October 1, 2017, between APX, Inc. ("APX") and NEPOOL (the "GIS Agreement"). Stored Solar requests this relief so that NEPOOL can direct APX to correct monthly generation data on active GIS Certificates for Stored Solar's Ryegate 1 biomass generating facility ("Ryegate 1"). This memorandum describes the relevant facts, Rules and provisions of the GIS Agreement. Attachment 1 to this memorandum is a proposed form of Waiver Agreement between NEPOOL and APX to be used if NEPOOL decides to grant the requested waiver. Stored Solar has provided an explanation of why it believes its requested relief is appropriate, which is being distributed with this memorandum.

Ryegate 1 is a 20 MW wood-fired generation facility that is eligible for renewable energy credits under the Connecticut and New Hampshire renewable portfolio standards ("RPS"). The GIS creates and tracks Certificates that are used to evidence those renewable energy credits.[1] Ryegate 1 was registered in the GIS as a multi-fuel (wood and natural gas) generating unit by a prior owner of the facility, and that registration has not been changed since that time. Under Rule 2.5(d), each Certificate for a multi-fuel unit reflects only one fuel source, with the split of total Certificates issued for any month for that unit reflecting the proportion of output per fuel type in that month. The Rule further states:

> With its initial registration and by the fifth calendar day preceding each Creation Date thereafter, each GIS Generator and Importing Account Holder that has registered a generating unit with multi-fuel capability will submit to the GIS Administrator information reflecting the proportion of output per fuel type, by MWh, generated by the unit during each month in the applicable calendar quarter to which such Creation Date relates, using available sources of information. Such information shall be used to allocate Certificates for such multi-fuel generating units for each month for which it was supplied.

Stored Solar states that Ryegate 1 uses natural gas (propane) only for plant start-up, and almost all of its output is produced by biomass (wood). There is no natural gas transmission line

[1] Each Certificate in the GIS represents 1 MWh of generation.

to the plant and therefore a propane tank similar to Stored Solar's other plants is used to ignite the biomass at start-up. For the months of February 2021 and March 2021, Stored Solar incorrectly entered the production by fuel type for each month, such that the biomass output was entered as natural gas output, and the natural gas output was entered as biomass output. As a result, the Certificates issued on July 15, 2021 for Ryegate 1 for those two months reflected the following:

Month	Biomass Output	Natural Gas Output
February 2021	0 MWh	13,151.56 MWh
March 2021	2.06 MWh	14,426 MWh

Vermont Electric Power Producers, Inc. ("VEPPI"), as administrator of the Vermont Standard Offer Program, transfers 50 percent of the Certificates generated by Ryegate 1 to sixteen Vermont utilities on a pro rata basis. Those utilities then sell the Certificates to entities that can use them to satisfy the Connecticut and New Hampshire RPSs. Since only Ryegate 1's biomass output is eligible for the RPSs in Connecticut and New Hampshire, the error in allocating the output by fuel types between biomass and natural gas results in only two of the GIS Certificates issued for February and March for the facility being RPS eligible, whereas if the fuel types had been entered correctly, 27,578 eligible Certificates would have been issued for that month. Stored Solar was supposed to have delivered the correctly categorized Certificates to the Vermont utilities in August. Stored Solar estimates that it will lose approximately $1,000,000 as a result of the Certificates being issued with the incorrect fuel types.

Stored Solar has approached the regulators in Connecticut and New Hampshire about permitting the Ryegate 1 Certificates for February and March that were erroneously reported as generated by natural gas to be recognized as having been produced by biomass and accordingly eligible to satisfy the respective RPSs. Both sets of regulators have reportedly indicated to Stored Solar that, in order to be counted as having been produced by biomass, the Certificates must be corrected in the GIS. Stored Solar requested that APX correct the Certificates after they had been issued. APX declined that request, concluding that it did not have the contractual authority to grant it.

The documents that govern APX's contractual authority over the GIS are found in the GIS Agreement and GIS Operating Rules. Section 4.2 of the GIS Agreement and Rule 1.4 require APX to administer and operate the GIS in accordance with the GIS Operating Rules. APX, as the GIS Administrator, has under those provisions "the sole responsibility for the compilation, indexing, reasonable interpretation and implementation of the GIS Operating Rules." There is no Rule that permits adjustments to Certificates following their creation due to a data entry error by a GIS account holder. Rule 2.8(a), which APX referenced to Stored Solar, states:

> A GIS Generator or Importing Account Holder may request that the GIS Administrator adjust the number of Certificates to be created for it (or, if Certificates of different types or classes are being created for the same GIS Generator or Importing Account Holder, the number of Certificates of each type created for it) at least five calendar days prior to the Creation Date on which such Certificates will be created.

APX indicated to NEPOOL counsel that it would be willing to waive these contractual requirements and grant Stored Solar's request to correct the inaccurate Certificates issued to Stored Solar on July 15, 2021 if NEPOOL, as the counterparty to the GIS Agreement, agreed to such a waiver and directed APX to correct the Certificates. Stored Solar, which is a NEPOOL Participant, has requested such a waiver. In order to ensure that any potentially affected entities are aware of this waiver request APX will provide a notice to all GIS account holders and direct them to provide any input on those waivers to NEPOOL counsel prior to the Participants Committee meeting.

Section 13.5 of the GIS Agreement requires that any modifications of that agreement be in writing signed by both NEPOOL and APX. The waivers of the GIS Agreement provisions and the Rules identified herein are therefore reflected in the proposed Waiver Agreement included with this memorandum as Attachment 1. The Waiver Agreement has been drafted to apply only to the current situation involving Stored Solar and would not otherwise change any Rule or the GIS Agreement. Any similar waivers of the Rules in the future would also require the approval of the Participants Committee. The approval of the Waiver Agreement requires a two-thirds Vote of the Participants Committee.

As reflected in the forms of resolutions below, if the Participants Committee wishes to grant the requested waiver, it must also take a number of related actions to effect the Waiver Agreement. One resolution, if passed, would approve the form of Waiver Agreement to accomplish the waiver required to instruct APX to correct the Certificates. A second resolution, if passed, would authorize the Participants Committee Chair to execute the Waiver and would direct NEPOOL counsel to take such actions as deemed reasonably necessary to implement the Waiver Agreement if approved.

The following forms of resolutions can be used for Participants Committee actions on this matter as described above:

> RESOLVED, that the Participants Committee (i) approves the temporary waivers of the relevant GIS Operating Rules and the relevant section of the GIS Agreement, as set forth in the Waiver Agreement circulated to this Committee and posted with the materials for this meeting, and (ii) instructs APX, as the GIS Administrator, to correct certain GIS Certificates issued to Stored Solar J&WE, LLC, in each case as described in the materials circulated in advance of this meeting.
>
> RESOLVED, that the Participants Committee Chair is authorized to execute the Waiver Agreement on behalf of NEPOOL in the form circulated in advance of this meeting with such non-material changes thereto as may be approved by the Participants Committee Chair, and NEPOOL Counsel is directed and authorized to make any filing(s) and take any other actions as it deems reasonably necessary to implement the Waiver Agreement.

Attachment 1

WAIVER AGREEMENT

This WAIVER AGREEMENT (this "Waiver") is made effective as of the 2nd day of September, 2021 by and among APX, Inc., a California corporation ("APX"), and the entities that are Participants from time to time in the New England Power Pool, pursuant to the Restated New England Power Pool Agreement dated as of September 1, 1971, as amended and restated to date and as further amended and/or restated from time to time, acting herein by and through the Participants Committee ("NEPOOL"). This waiver is made under the Amended and Restated Generation Information System Administration Agreement dated as of October 1, 2017 between APX and NEPOOL (the "GIS Agreement"). APX and NEPOOL may be referred herein as the "Parties" and each may be referred to as a "Party." Capitalized terms used in this Waiver and not otherwise defined have the meanings assigned to such terms in the GIS Agreement.

WHEREAS, Rules 2.5(d) and 2.8(a) of the NEPOOL Generation Information System ("GIS") Operating Rules ("Rules") require that certain information for multi-fuel generating units, and requests for changes to that information, be provided no later than five days prior to the Creation Date for the Certificates to be issued based on that information (the "Certificate Information Deadline"); and

WHEREAS, Rule 1.4(a) and Section 4.2 of the GIS Agreement require APX to administer the GIS in accordance with the Rules; and

WHEREAS, Rule 1.4(b) and Section 4.2 of the GIS Agreement state that APX, as the GIS Administrator, shall have the sole responsibility for the compilation, indexing, reasonable interpretation and implementation of the Rules; and

WHEREAS, NEPOOL Participant Stored Solar J&WE, LLC ("Stored Solar") is the GIS account holder for the Ryegate 1 generating unit, which is registered as a generating unit with multi-fuel capability under Rule 2.5(d) of the Rules; and

WHEREAS, Stored Solar has requested that APX change information on its Certificates for the first quarter of 2021 after the Certificate Information Deadline to correct a reporting error made by Stored Solar such that (i) the Certificates issued for generation in February 2021 and March 2021 that had erroneously identified natural gas as the fuel source be corrected to identify wood as a fuel source and (ii) Certificates issues for generation in February 2021 and March 2021 that had erroneously identified wood as the fuel source be corrected to identify natural gas as the fuel source (the "Stored Solar Adjustment"); and

WHEREAS, APX has determined that absent a waiver by both APX and NEPOOL of the GIS Agreement and applicable Rules, APX does not have the contractual authority to effect the requested Stored Solar Adjustment; and

WHEREAS, APX is willing to agree to waive the applicable GIS Agreement and Rules but only if NEPOOL also agrees to such a waiver and directs APX to make the Stored Solar Adjustment; and

WHEREAS, the NEPOOL Participants Committee voted on September 2, 2021 to authorize this Waiver Agreement and to direct APX to make the Stored Solar Adjustment;

NOW, THEREFORE, in consideration of the foregoing and for other good and valuable consideration, the receipt and sufficiency of which are acknowledged, the Parties agree as follows:

1. The Parties waive Rules 1.4(a), 1.4(b), 2.5(d) and 2.8(a) and Section 4.2 of the GIS Agreement solely to the extent necessary for APX to make the Stored Solar Adjustment prior to September 15, 2021.

2. NEPOOL directs APX to make the Stored Solar Adjustment prior to September 15, 2021, notwithstanding the provisions of the Rules.

3. This Waiver shall be governed by, and construed and enforced in accordance with, the laws of the State of Connecticut.

4. This Waiver may be executed by the Parties in counterparts, each of which shall be deemed an original and which, taken together, shall be deemed to constitute one and the same instrument. Facsimile signatures on this Waiver, including those transmitted in portable document format (.pdf) or other electronic means, shall have the effect of original signatures thereon.

5. This Waiver shall be binding upon and inure to the benefit of the Parties hereto and their respective successors and assigns.

6. Except as specifically waived hereby, all terms and provisions contained in the GIS Agreement and the Rules shall remain unchanged and in full force and effect.

7. The waivers of rights under this Waiver are limited solely to the matters and times set forth herein. This Waiver sets forth the entire understandings of the Parties with respect to the matters addressed herein and supersedes any prior negotiations or agreements, whether written or oral, with respect thereto. As provided in Section 13.1 of the GIS Agreement, no waiver of rights under this Waiver shall be deemed to be a waiver with respect to any other matter arising under the GIS Agreement.

[*Signature Page Follows*]

IN WITNESS WHEREOF, the Parties have executed this Waiver as of the date first above written.

NEW ENGLAND POWER POOL, acting through the NEPOOL Participants Committee

By ______________________________
Name: David A. Cavanaugh
Title: Chair of the NEPOOL Participants Committee

APX, INC.

By ______________________________
Name:
Title:

Stored Solar, LLC
1231 Main Road
West Enfield, ME 04493

NEPOOL
New England Power Pool
Participants Committee

VIA EMAIL: Belval, Paul N. <pnbelval@daypitney.com>

Dear Committee Members:

Our staff when entering the emission data for the Ryegate facility for the first quarter of this year made a mistake and placed the correct emissions numbers in the wrong box.

We feel that the error is so obvious that the correction of this should not be controversial, however the error was not caught by us, or the GIS Administrator before the portal was officially closed. On numerous occasions the GIS office has called us when something looked wrong with the emissions data. The emissions data entered for February and March for Ryegate was correct and inconsistent with natural gas as a fuel. While we don't rely on the GIS Administrator's office to correct our entries, we feel there is enough blame to go around for us, and/or the GIS Administrator's office, for not recognizing the error in sufficient time to correct it while the portal was open.

The root cause of the error even being allowed, is that the set-up of the facility was wrong from the beginning. It is a single fuel plant and was incorrectly set up as dual fuel. This site has no access to natural gas. As in all our other biomass plants (eight in total), a start-up fuel is used. As in Ryegate, several of the plants have propane tanks for lighting the biomass, while others without propane use a combination of oily rags, newspaper, and other means of lighting the biomass fuel. None of our other plants are categorized as dual fuel. I checked with our managers who have worked for other companies on other biomass plants, and they have told me they never had an issue with them being categorized as dual fuel. I think the previous allocation was merely a result of having two boxes and the individual input should not have been split, however it is amount of heat input allocated as a start-up fuel. This allocation is not customary and does not occur on other similar plants in our portfolio and to our knowledge other owners as well. We plan to take the steps required to correct this set-up, so an error of this type could not recur.

Additionally, in reviewing the GIS rules, we feel there is ambiguity caused by 2.8 (c) which states:

> (c) QEAs for EPA-provided emissions data for any calendar quarter that are provided to the GIS Administrator on or before the fifth day before the Creation Date for that calendar quarter shall be reflected on the Certificates created for that calendar quarter. QEAs for EPA-provided emissions data for

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Paul Belval and Samantha Regan, NEPOOL Counsel

DATE: August 31, 2021

RE: GIS Working Group Call to Discuss Request by Stored Solar of Waiver of GIS Operating Rules and GIS Agreement

---

The NEPOOL GIS Operating Rules Working Group met by teleconference on August 27, 2021 to discuss Stored Solar's request for a waiver of the GIS Operating Rules and the GIS Administration Agreement in order to permit a correction of generation data on active GIS Certificates for its Ryegate 1 Facility. A summary of the Working Group's questions and comments is below:

One of the Working Group members who was involved in drafting the GIS Operating Rules said the purposes of barring changes of monthly generation data after Certificates are created were (1) to ensure that the Certificates will not lose value due to a material change in the Certificate's data and (2) to ensure that there is not a significant impact in the market value of Certificates due to a change in supply or demand. Stored Solar's request would not adversely impact the value of issued Certificates because it would merely correct data on the Certificates to what it should have been initially. Additionally, the market expects the Certificates generated from the Rygate 1 Facility, as the Facility is a regular market participant generating these Certificates and therefore, participants in the market would expect the change in supply from altering the Ryegate 1 Certificates.

Another member asked who would benefit and who would be harmed from not correcting the Ryegate 1 Certificates. The response was that no one would likely benefit because the Certificates that would have been created do not exist, and those that would have benefitted from the Certificates (including the Vermont utilities who receive 50 percent of those Certificates) must purchase alternative Certificates.

One member said that with similar issues in the past, the GIS Certificates were not changed, but instead the Certificates were transferred to the buyer and the state regulators agreed to accept the Certificates for compliance with the applicable state program.

A representative of the Connecticut Public Utilities Regulatory Authority said it is not willing to accept the Ryegate 1 Certificates at issue for RPS compliance unless they are corrected in the GIS. Connecticut PURA's position is that it cannot police Certificates to the degree it would like to in order to make these types of decisions, and instead it must rely on the GIS to address these issues.

A member noted that the GIS Rules have not been waived previously and voiced concern regarding fairness to other Participants who had not had the opportunity to correct such errors in the past. Further, the requirement that generators manually input their Certificate data monthly may call for a rule change around duel-unit reporting requirements to decrease the likelihood of these errors occurring in the future.

Two members voiced concern regarding the short timeframe of Stored Solar's request for relief. One of those members recommended that Stored Solar move its request to the October meeting agenda to give the Participants Committee and Stored Solar an opportunity to discuss this request more fully.

Stored Solar, LLC
1231 Main Road
West Enfield, ME 04493

> any calendar quarter that are provided to the GIS Administrator after the fifth day before the Creation Date for that calendar quarter shall be reflected on the Certificates created on the next Creation Date, so long as such subsequently created Certificates relate to generation that occurred in the same calendar year as the emissions that are the subject of any such QEA. Any QEA that is provided to the GIS Administrator after the fifth day before the Creation Date for the fourth quarter Trading Period for the applicable calendar year will be disregarded by the GIS Administrator.

In spite of the fact that the RECs in question are not QEAs, this would infer, that adjustments can be made except in fourth quarter RECs. Since these are first quarter RECs there should no harm to the system to make the change to correct this clerical error, provided it is not for fourth quarter RECs.

The RECs generated by the Ryegate plant are shared with all Vermont power producers, so the failure to remedy this clerical error would cause irreparable damage to the entire State of Vermont.

We respectfully request that your committee quickly allow this correction to be made since the GIS Administrator has agreed to allow the correction upon the instruction of NEPOOL.

If you have any questions regarding the above, I am available to discuss them with you at your convenience.

Sincerely,

William J. Harrington
Director and Vice President
Stored Solar, LLC
bharrington@storedsolarllc.com
(219) 712-4764 Cellular

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of August 31, 2021

The following activity, as more fully described in the attached litigation report, has occurred since the report dated August 3, 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 (EL21-47)	Aug 6	National Grid answers Green Development's Jul 27 motion renewing request for fast track processing of its Feb 10, 2021 Complaint
			Aug 20	Green Development submits additional information

II. Rate, ICR, FCA, Cost Recovery Filings

*	7	VTransco Request to Defer 2021/22 Retiree Lump Sum Payment Cost Recovery (ER21-2627)	Aug 5	VTransco requests authorization to defer retiree costs
			Aug 25	VT DPS supports request
	7	FCA16 De-List Bids Filing (ER21-2342)	Aug 17	FERC accepts filing, eff. Aug 30, 2021
	7	CSC CIP IROL Cost Recovery: Pre-Jun 1, 2021 Regulatory Asset Cost Recovery (ER21-2334)	Aug 6	CSC answers NESCOE protest
			Aug 31	FERC denies CSC authorization to establish a regulatory asset to include and recover costs under Schedule 17 for CIP-IROL costs prudently incurred between Jan 1, 2016 and May 31, 2021 ($1.324 million)
	8	Mystic 8/9 Cost of Service Agreement (ER18-1639)	Aug 13, 16	Mystic, CT Parties, ENECOS, MA AG file requests for rehearing of *Mystic ROE Order*
			Aug 16	Mystic files fifth compliance filing to reflect revised ROE in COS Agreement; comment deadline ***Sep 7, 2021***
*	9	2020/2021 Power Year Transmission Rate Filing (ER09-1532; RT04-2)	Jul 31	PTO AC submits informational filing identifying adjustments to regional transmission service charges for the Jun 1, 2020 to May 31, 2021 period (RNS Rate of $129.26/kW-year and a Schedule 1 formula rate of $1.745 kW-year, increases of $17.32 /kW-year and $0.152/kW-year, respectively); this filing will not be noticed for public comment

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

	9	Removal of Appendix B from Market Rule 1; Deletion of Assoc. Tariff Provisions (ER21-2220)	Aug 13	FERC accepts revisions, eff. Aug 27, 2021
	10	ORTP Jump Ball Filing (ER21-1637)	Aug 9	FERC issues a "Notice of Denial of Rehearing by Operation of Law and Providing for Further Consideration" of Clean Energy Advocates' request for rehearing of the *ORTP Jump Ball*
			Aug 10	FERC accepts ISO-NE's compliance filing, eff. June 8, 2021
			Aug 26	FERC issues *ORTP Jump Ball Allegheny Order*, modifying the *ORTP Jump Ball Order,* but sustaining the results of that *Order*

V. OATT Amendments / TOAs / Coordination Agreements

	12	TOs *Order 676-I* Compliance Filing (ER21-2529)	Aug 13	National Grid intervenes
	12	CSC *Order 676-I* Compliance Filing (ER21-2509)	Aug 13-16	CSC and National Grid intervene
	11	BTM Generation Proposal (ER21-2337)	Aug 6	PTO AC answers NEPGA protest
			Aug 12	NEPGA answers PTO AC Aug 12 answer
			Aug 16	IMM answers PTO AC answer
			Aug 20	FERC issues deficiency letter; responses due ***Sep 20, 2021*** (submission of responses will re-set the deadline for FERC action)

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Changes

*	12	Schedule 20A-UI: Vitol Phase I/II HVDC-TF Service Agreement (ER21-2662)	Aug 12	UI files Phase I/II HVDC-TF Service Agreement with Vitol; comment deadline ***Sep 2, 2021***
			Aug 27	Vitol intervenes
*	13	Schedule 20A-CMP: Vitol Phase I/II HVDC-TF Service Agreement (ER21-2661)	Aug 12	CMP files Phase I/II HVDC-TF Service Agreement with Vitol; comment deadline ***Sep 2, 2021***
			Aug 27	Vitol intervenes

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

*	14	Capital Projects Report - 2021 Q2 (ER21-2632)	Aug 9	ISO-NE files Q2 Report
			Aug 16	NEPOOL intervenes and files comments
			Aug 30	Eversource and National Grid intervene
*	15	Interconnection Study Metrics Processing Time Exceedance Report Q2 2021 (ER19-1951)	Aug 13	ISO-NE files required quarterly report
*	15	IMM Quarterly Markets Reports - 2021 Spring (ZZ21-4)	Aug 6	IMM files Spring 2021 Report
*	15	ISO-NE FERC Form 3Q (2021/Q2) (not docketed)	Aug 30	ISO-NE submits its 2021 Q2 FERC Form 3Q

IX. Membership Filings

*	15	September 2021 Membership Filing (ER21-2802)	Aug 30	***New Members***: Gravel Pit Solar, Tyr Energy, and Walden Renewables Development; ***Terminations***: Brookfield Energy Marketing Inc., HIKO Energy and Perigee Energy; comment deadline ***Sep 21, 2021***
	16	July 2021 Membership Filing (ER21-2267)	Aug 25	FERC accepts filing

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

	16	Revised Reliability Standards (Cold Weather Reliability Standards): EOP-011-2; IRO-010-4; and TOP-003-5 (RD21-5)	Aug 6 Aug 24	PJM and MISO submit joint comments FERC approves Cold Weather Reliability Standards, eff. Apr 1, 2023
*	18	2022 NERC/NPCC Business Plans and Budgets (RR21-9)	Aug 24	NERC submits proposed 2022 Business Plan and Budget for itself and its Regional Entities, including NPCC; comment deadline ***Sep 14, 2021***
*	19	Rules of Procedure Changes (Rel. Standards Development Revisions) (RR21-8)	Aug 18	NERC files for approval changes to Reliability Standards Development ROP § 300 and Appendices 3B and 3D; comment deadline ***Sep 8, 2021***
	19	5-Year ERO Performance Assessment Report (RR19-7-002)	Aug 17	FERC approves NERC's May 19, 2021 compliance filing, eff. Aug 17, 2021

XI. Misc. - of Regional Interest

*	20	203 Application: Valcour Wind Energy/AES (EC21-114)	Aug 13	Valcour and AES, among others, request authorization for a transaction whereby AES will become Valcour's majority upstream owner; comment deadline ***Sep 3, 2021***
*	20	203 Application: Covanta/EQT (EC21-113)	Aug 11 Aug 12	Covanta requests authorization for a transaction whereby EQT will indirectly acquire Covanta; comment deadline Sep 1, 2021 PJM IMM intervenes
*	20	203 Application: Cypress Creek/EQT (EC21-108)	Aug 26	PJM IMM intervenes out-of-time
	21	203 Application: NRG/Generation Bridge (ArcLight) (EC21-74)	Aug 18	FERC authorizes Generation Bridge acquisition of NRG Project Companies
	21	203 Application: Exelon Generation (EC21-57)	Aug 24	FERC authorizes "spin" transaction that will separate Exelons' regulated utilities from ExGen's Public Utility Subsidiaries
*	21	TSAs: Third Amendments to NECEC Transmission TSAs (ER21-2738 et al.)	Aug 23	NECEC Transmission files third amendments to TSAs with the participants that will fund the NECEC Project; comment deadline ***Sep 13, 2021***
*	21	Seabrook/NECEC E&P Agreement (ER21-2719)	Aug 19 Aug 30	Seabrook files E&P Agreement; comment deadline ***Sep 9, 2021*** National Grid intervenes
*	22	ISA: NSTAR/Servistar (ER21-2696)	Aug 16	NSTAR files ISA, comment deadline ***Sep 7, 2021***
*	22	D&E Agreement: NSTAR/Medway Grid II (ER21-2684)	Aug 16	NSTAR files second D&E Agreement; comment deadline ***Sep 7, 2021***
	22	Versant Waiver Request: Unreserved Transmission Use Penalty Policy (ER21-2447)	Aug 6 Aug 11	Black Bear files comments Versant answers Black Bear's comments
	23	D&E Agreement: NSTAR/Hingham Municipal Light Plant (ER21-2281)	Aug 20	FERC accepts Agreement, eff. Jul 1, 2021
	23	D&E Agreement: NSTAR/Medway Grid I (ER21-2273)	Aug 26	FERC accepts Agreement, eff. Jul 1, 2021
	23	Amended and Restated IRH Support and Use Agreements eTariff Compliance Filings (ER21-2163 et al.)	Aug 4 Aug 17-18	VETCO files errata to its Phase I VT Transmission Line Support Agreement filing (ER21-2158) FERC accepts all but the VETCO Phase I VT Transmission Line Support Agreement, eff. Jan 1, 2021

XII. Misc. - Administrative & Rulemaking Proceedings

25	Joint Federal-State Task Force on Electric Transmission (AD21-15)	Aug 30	FERC issues order listing the 10 state commissioner members, announcing a first public meeting of the Task Force (Nov 10, 2021), and inviting agenda topics; agenda topic deadline ***Sep 10, 2021***
26	Climate Change, Extreme Weather, and Elec. Sys. Reliability: Jun 1-2 Tech. Conf. (AD21-13)	Aug 11	FERC issues a notice inviting post-technical conference comments; comment deadline ***Sep 27, 2021***
26	Electrification and the Grid of the Future (AD21-12)	Aug 18	R Street Institute submits late-filed comments
27	Modernizing Electricity Market Design - Energy and Ancillary Service Markets (AD21-10)	Aug 17	FERC issues supplemental notice of the first of the 2 staff-led tech confs (***Sep 14, 2021***) to discuss potential energy and ancillary services market reforms that may be needed as the resource fleet and load profiles change over time
27	Office of Public Participation (AD21-9)	Aug 23	FERC issues notice of a virtual workshop to be held on ***Sep 16, 2021*** to discuss technical assistance in electric proceedings, solicit public input on their technical assistance needs, and explore ways OPP could facilitate technical assistance to interested parties
29	Hybrid Resources (AD20-9)	Aug 9	FERC grants ESA request for 30-day extension of time to file comments in response to the ISO/RTO reports; comment deadline ***Sep 20, 2021***
		Aug 18	City of New York files comments
29	ANOPR: Transmission Planning and Allocation and Generator Interconnection (RM21-17)	Aug 6, 19-20	IRC, OPSI and OMS request extension of time to submit comments, which would extend the comment date to Dec 1, 2021 (an additional 50 days), and reply comments to Jan 31, 2022 (an additional 30 days to the reply comment period)
		Aug 18-19	eight individuals file comments
30	NOI: Removing the DR Opt-Out in ISO/RTO Markets (RM21-14)	Aug 23	AEP, Armada Power, Entergy, Southern Pioneer Electric, Voltus, State Commissions from LA/MS, MI, MO, NC, APPA/NRECA, ABATE, and PIOs file reply comments
31	NOPR: Electric Transmission Incentives Policy (RM20-10)	Aug 23	New England State Parties, Alliant/Consumers/DTE, AEP, Pacific Gas & Electric, Joint Consumer Advocates, and ACPA post reply comments;
		Aug 23	FERC issues supplemental notice of ***Sep 10 workshop***
34	*Order 860/860-A*: Data Collection for Analytics & Surveillance and MBR Purposes (RM16-17)	Aug 19	FERC issues order revising MBR Data Dictionary; baseline compliance filings due ***Nov 2, 2021***
24	*Orders 864/864-A* (Public Util. Trans. ADIT Rate Changes): New England Compliance Filings (various)	Aug 27	*ER20-2614-001 (National Grid)*. National Grid files *Order 864* revisions to Phase II Facilities AC Support Agreement
		Aug 26	*ER20-2610-001 (CL&P)*. CL&P files *Order 864* revisions to Millstone TSA *ER20-2609-001 (NSTAR)*. NSTAR files *Order 864* revisions to Phase II Boston Edison AC Facilities Support Agreement
		Aug 20	*ER20-2608-001/2607-001 (PSNH, Seabrook)*. PSNH and National Grid file *Order 864* revisions to their Seabrook TSA compliance filings

XIII. FERC Enforcement Proceedings

39	GreenHat (IN18-9)	Aug 23	The Estate of Andrew Kittell replies to Enforcement's Jul 27 answer
41	Total Gas & Power North America, Inc. et al. (IN12-17)	Aug 19	Presiding ALJ Krolikowski issues notice of Aug 26 prehearing conf.
		Aug 26	Presiding ALJ Krolikowski convenes prehearing conference

XIV. Natural Gas Proceedings

42	Iroquois ExC Project (CP20-48)	Aug 4-23 Aug 24	93 sets of individual comments filed Algonquin responds to comments

XV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XVI. Federal Courts

47	*Opinion 531-A* Compliance Filing Undo (20-1329)	Aug 24	FERC submits status report indicating that the proceedings before the Commission remain ongoing and that this appeal should continue to remain in abeyance
48	2013/14 Winter Reliability Program Order on Compliance and Remand (20-1289, 20-1366) (consol.)	Aug 6	Court schedules oral argument for ***Oct 15, 2021***
48	ISO-NE's Inventoried Energy Program Proposal (19-1224***; 19-1247; 19-1252; 19-1253)(consol.)	Aug 6	Court schedules oral argument for ***Oct 21, 2021***
50	*Opinion 569/569-A*: FERC's Base ROE Methodology (16-1325 et al.) (consol.)	Aug 5 Aug 19	Joint Deferred Appendix filed Final Briefs filed
50	Algonquin Atlantic Bridge Project *Briefing Order* (21-1115; 21-1138, 21-1153, 21-1155) (consol.)	Aug 16 Aug 27	FERC requests Court to extend abeyance by an additional 60 days Court grants second abeyance motion by the FERC, directing parties to file motions to govern future proceedings by ***Oct 29, 2021***

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: September 1, 2021

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

We have summarized below the status of key ongoing proceedings relating to NEPOOL matters before the Federal Energy Regulatory Commission ("FERC"),[1] state regulatory commissions, and the Federal Courts and legislatures through August 31, 2021. If you have questions, please contact us.

COVID-19

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

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

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

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

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

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

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

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

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

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

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

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

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

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

I. Complaints/Section 206 Proceedings

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

Pending before the FERC is the February 10, 2021 complaint by Green Development, LLC ("Green Development") 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 (the "Complaint"). Green Development asserts that the upgrades associated with the interconnection of its distribution-level, state jurisdictional projects are not DAF as defined in the ISO-NE Tariff. National Grid filed its answer on March 2, 2021. 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"). On March 23, Green Development and SEIA answered National Grid's March 2 answer. On April 9, National Grid answered those answers. On July 27, 2021, Green Development submitted a motion renewing and reiterating its request for fast track processing of its Complaint. On August 20, 2021, Green Development submitted additional information to (i) clarify/confirm its understanding that the first DAF Charge payments would be due under the Interconnection Service Agreements ("ISAs") 30 days prior to the applicable in-service date, anticipated to be in November 2021; (ii) note that the ISAs were being amended to clarify when the first DAF charges will be due; and (iii) note that its July 27 request "remains valid and appropriate". This matter remains pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

On May 28, 2021, the FERC denied NEPGA's December 11, 2020 Net CONE complaint against ISO-NE.[12] 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.[13] In denying the Complaint, the FERC found that ISO-NE

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

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

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

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

[12] *New England Power Generators Assoc., Inc. v. ISO New England Inc.*, 175 FERC ¶ 61,177 (May 28, 2021) ("*NEPGA Net Cone Complaint Order*"), *reh'g denied*, 176 FERC ¶ 62,058 (July 29, 2021).

[13] NEPGA also asked the FERC to find unjust and unreasonable the Net CONE value for FCAs 16-18 filed in ER21-787. Those values were conditionally accepted in a concurrently-issued order (*see* ER21-787 in Section III below). In the *NEPGA Net Cone Complaint Order*, the

did not violate its current Tariff or the filed rate doctrine by using the proposed methodology to recalculate Net CONE. The FERC said that ISO-NE was "entitled to file a revised Net CONE definition pursuant to FPA section 205 and, as such, it was appropriate for ISO-NE to have performed its Net CONE calculations for the next FCA consistent with the definition it intended to file and have in effect in advance of that FCA".[14] Assertions regarding the impact of the proposed methodology to the market were left to be addressed in ER21-787 (*see* Section III below).[15]

Request for Rehearing Denied by Operation of Law. On June 28, 2021, EPSA and NEPGA jointly requested rehearing of both the *NEPGA Net Cone Complaint Order* and the *Updated CONE, Net Cone and PPR Values Order*. On July 29, 2021, the FERC issued a "Notice of Denial of Rehearing by Operation of Law and Providing for Further Consideration".[16] The Notice confirmed that the 60-day period during which a petition for review of the *NEPGA Net Cone Complaint Order* can be filed with an appropriate federal court was triggered when the FERC did not act on the requests for rehearing of the *NEPGA Net Cone Complaint Order*. The Notice also indicated that the FERC would address, as is its right, the rehearing request in a future order, and may modify or set aside its order, in whole or in part, "in such manner as it shall deem proper."

If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

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

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

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

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FERC said that NEPGA had not demonstrated that substituting the Net CONE values calculated using the old methodology (undoing the filing in ER21-787) was appropriate or necessary to address the alleged filed rate doctrine violation. *NEPGA Net Cone Complaint Order* at P. 55.

[14] *Id.* at P 53.

[15] *Id.* at P 54.

[16] *New England Power Generators Assoc., Inc. v. ISO New England Inc.*, 176 FERC ¶ 62,058 (July 29, 2021) ("*Order Denying NEPGA Net Cone Complaint Order*").

[17] 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.

no activity in this proceeding since the last Report and this matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

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

Comments on Seabrook's Petition were filed by Eversource, MMWEC and NEPGA. Avangrid and NECEC Transmission ("Avangrid") protested the Declaratory Order Petition. Doc-less interventions were filed by Avangrid, Dominion, Eversource, Calpine, Exelon, HQ US, National Grid, NESCOE, NRG, and Public Citizen. NextEra answered Avangrid's protest and Avangrid answered NextEra's answer. On May 6, 2021, ISO-NE submitted a letter in this proceeding, as well as in EL21-6, to express importance of prompt resolution of these matters. There has been no activity in this proceeding since the last Report and this matter also remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Base ROE Complaints I-IV: (EL11-66, EL13-33; EL14-86; EL16-64)**

There are four proceedings pending before the FERC in which consumer representatives seek to reduce the TOs' return on equity ("Base ROE") for regional transmission service.

  - ***Base ROE Complaint I (EL11-66)***. In the first Base ROE Complaint proceeding, the FERC concluded that the TOs' ROE had become unjust and unreasonable,[18] set the TOs' Base ROE at 10.57% (reduced from 11.14%), capped the TOs' total ROE (Base ROE <u>*plus*</u> transmission incentive adders) at 11.74%, and required implementation effective as of October 16, 2014 (the date of *Opinion 531-A*).[19] However, the FERC's orders were challenged, and in *Emera Maine,*[20] the DC Circuit vacated the FERC's prior orders, and remanded the case for further proceedings consistent with its order. The FERC's determinations in *Opinion 531* are thus no longer precedential, though the

[18] 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*")).

[19] *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*").

[20] *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).

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)[21] and third (EL14-86)[22] 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.[23] 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[24] also went to hearing before an ALJ, Judge Glazer, who issued his initial decision on March 27, 2017.[25] 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.[26] 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.[27] 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*[28] (EL14-12; EL15-45) in

[21] 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%.

[22] 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.

[23] *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*").

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

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

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

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

[28] *Ass'n of Buss. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569-A, 171 FERC ¶ 61,154 (2020) ("*Opinion 569-A*"). The refinements to the FERC's ROE methodology included: (i) the use of the Risk Premium model instead of only relying on the DCF model and CAPM under both prongs of FPA Section 206; (ii) adjusting the relative weighting of long- and short-term growth rates, increasing the weight for the short-term growth rate to 80% and reducing to 20% the weight given to the long-term growth rate in the two-step DCF model; (iii) modifying the high-end outlier test to treat any proxy company as high-end outlier if its cost of equity

Section XI below). The FERC established a paper hearing on how its proposed methodology should apply to the four pending ROE proceedings.[29]

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%.[30] 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[31] for an extension of time to submit briefs, the latest date for filing initial and reply briefs was extended to January 11 and March 8, 2019, respectively. On January 11, initial briefs were filed by EMCOS, Complainant-Aligned Parties, TOs, EEI, Louisiana PSC, Southern California Edison, and AEP. As part of their initial briefs, each of the Louisiana PSC, SEC and AEP also moved to intervene out-of-time. Those interventions were opposed by the TOs on January 24, 2019. The Louisiana PSC answered the TOs' January 24 motion on February 12. Reply briefs were due March 8, 2019 and were submitted by the TOs, Complainant-Aligned Parties, EMCOS, FERC Trial Staff.

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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*.

[29] *Id.* at P 19.

[30] *Id.* at P 59.

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

TOs Request to Re-Open Record and file Supplemental Paper Hearing Brief. On December 26, 2019, the TOs filed a Supplemental Brief that addresses the consequences of the November 21 *MISO ROE Order*[32] and requested that the FERC re-open the record to permit that additional testimony on the impacts of the *MISO ROE Order*'s changes. On January 21, 2020, EMCOS and CAPs opposed the TOs' request and brief.

These matters remain pending before the FERC. If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Joe Fagan (202-218-3901; jfagan@daypitney.com).

II. Rate, ICR, FCA, Cost Recovery Filings

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

On August 5, 2021, Vermont Transco ("VTransco") requested authorization to defer for future recovery costs associated with lump sum payments to employees who retire in 2021 and 2022. VELCO expects a record number of employees to retire in 2021 (12) and 2022 and anticipates that many, if not most, of them will opt to take a lump sum payment, resulting in significantly higher one-time expenses to be passed through to VTransco than has historically been the case. VTransco's request is intended to mitigate the rate impact on the Vermont distribution utilities, and in turn, their retail ratepayers. VTransco's request was supported by the VT DPS. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **FCA16 De-List Bids Filing (ER21-2342)**

On August 17, 2021, the FERC accepted, effective August 30, 2021,[33] ISO-NE's filing describing the Permanent De-List Bids and Retirement De-List Bids, as well as the substitution auction test prices, that were submitted on or prior to the March 12, 2021 FCA16 Existing Capacity Retirement Deadline. ISO-NE reported that it received 1 Permanent De-List Bid, 13 Retirement De-List Bids, and 2 substitution auction test prices from 8 Lead Market Participants. The bids were for resources located in the CT, VT, ME, South Eastern Massachusetts, Northeastern Massachusetts Boston ("NEMA/Boston") and Western Central MA Load Zones, with 996.460 MWs of aggregate capacity. Six of the Bids, totaling 26.262 MW in aggregate, were for resources under 20 MW or that did not meet the affiliation requirements that would have required IMM review. Two of those six (representing 23.174 MWs) required substitution auction test price reviews because the Bids were for greater than 3 MWs. The IMM did review the remaining eight Bids (from three separate suppliers) for 232.240 MWs of capacity. The IMM also reviewed two substitution auction test prices that were not associated with a Retirement or Permanent De-List Bid. The two bids were from a single Market Participant and for a total of 737.958 MW. The IMM's determination regarding those bids is described in the version of the filing that was filed confidentially as required under §13.8.1(a) of Market Rule 1. Unless the August 17 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

On August 31, 2021, the FERC denied the request by Cross-Sound Cable Company LLC ("CSC") for authorization to establish a regulatory asset that would include all CIP-IROL Costs[34] that CSC prudently incurred between January 1, 2016 and May 31, 2021 ($1.324 million) and recover those costs under Schedule 17 (from all ISO-NE transmission customers) over a five-year period (beginning on the date the FERC makes

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

[33] *ISO New England Inc.*, Docket No. ER21-2342 (Aug. 17, 2021) (unpublished letter order).

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

this rate treatment and related cost recovery effective).[35] Relying on its *Schedule 17 Orders*,[36] which found that Schedule 17 permits recovery only of CIP-IROL costs incurred on or after the effective date of a FPA section 205 filing made by an IROL-Critical Facility owner to recover such costs, and recovery of CIP-IROL costs incurred prior to the effective date of any relevant, individual FPA section 205 filing would violate the rule against retroactive ratemaking, the FERC found that permitting the recovery here proposed by CSC would violate the filed rate doctrine.[37] The FERC rejected the alternative bases for FERC approval proposed by CSC.[38] Challenges to the *August 31 Order* are due on or before September 30, 2021. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

As previously reported, the FERC issued four orders in this proceeding in July 2020 (three on July 17 (together, the "*July 17 Orders*"); one on July 28, 2020). Each of the orders addressed in part or in whole the Cost-of-Service Agreement ("COS Agreement")[39] among Constellation Mystic Power ("Mystic"), Exelon Generation Company ("ExGen") and ISO-NE, which is to provide compensation for the continued operation of the Mystic 8 & 9 units from June 1, 2022 through May 31, 2024. As noted in Section XVI below, each of the *July 17 Orders*[40] (and the earlier, underlying orders) have been appealed to the DC Circuit. On July 15, 2021, the FERC issued an order setting the base ROE for the Mystic COS Agreement at 9.33%.[41] Activity since the last Report includes:

Requests for Rehearing of the Mystic ROE Order (-010, -011). Mystic, CT Parties,[42] ENECOS,[43] and the MA AG requested rehearing of the *Mystic ROE Order*. The requests for rehearing are pending, with FERC action required on or before September 13, 2021, or the requests will be deemed denied by operation of law.

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

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

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

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

[39] 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.

[40] 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).

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

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

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

ROE (Fifth) Compliance Filing (-012). On August 16, 2021, Mystic filed a revised COS Agreement in a fifth compliance filing, this time in response to the *Mystic ROE Order*: (1) changing the Cost of Common Equity figures from 10.71 percent to 9.33 percent in Schedule C of the Methodology, for both Mystic 8&9 and Everett Marine Terminal ("Everett"); and (ii) reducing the Annual Fixed Revenue Requirements ("AFRR") to $170,605,963 for the 2022/2023 Capacity Commitment Period ("CCP") and to $139,668,204 for the 2023/2024 CCP. In addition, because the ROE adjustment reduces the charge for regassification service from Everett and the return on investment in Everett, Mystic also submitted for information a revised Fuel Supply Agreement ("FSA") and Terminal Services Agreement ("TSA") with Distrigas of Massachusetts LLC. Comments on the fifth compliance filing are due on or before September 7, 2021.

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

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

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

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

- **Removal of Appendix B from Market Rule 1; Deletion of Assoc. Tariff Provisions (ER21-2220)**

On August 13, the FERC accepted Tariff changes that removed Appendix B (Imposition of Sanctions by the ISO) from Market Rule 1 and made conforming changes to the Tariff reflecting the removal of that Appendix.[44] As previously reported, ISO-NE concluded that the provisions of Appendix B, which established procedures and standards by which ISO-NE could impose sanctions, if subsequently approved by the FERC, for sanctionable conduct, were outdated, unclear, or internally inconsistent with other Tariff provisions. The removal of Appendix B and the associated changes were accepted August 27, 2021, as requested. Unless the August 13 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).

[44] *ISO New England Inc. and New England Power Pool Participants Comm.*, Docket No. ER21-2220 (Aug. 13, 2021) (unpublished letter order).

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

As previously reported, the FERC accepted in part and rejected in part pieces of ISO-NE's and NEPOOL's proposals, effective June 8, 2021.[45] Specifically, the FERC accepted NEPOOL's proposed ORTP value for battery storage and NEPOOL's proposed federal tax credits adjustments to the ORTPs for PV solar resources for FCA17 and FCA18. Otherwise, the FERC accepted ISO-NE's proposed ORTP values (including ISO-NE's Offshore Wind ORTP value (on which the Commissioners split 3-2; *see* separate dissents by Commrs. Glick and Clements, who agreed with NEPOOL's Offshore Wind ORTP)) and ISO-NE's proposal to maintain the current Tariff language regarding economic life determination and the establishment of ORTPs for hybrid and co-located resources in the FCM (rejecting NEPOOL's proposed Tariff revisions in each case). The FERC also rejected NEPOOL's proposal to require ISO-NE to account for future federal tax credit changes through the Tariff's indexing process, finding instead that such changes are more appropriately made through a FERC filing when and if such changes are made. With respect to other issues, the FERC rejected (i) Generation Owners' argument that accepting either the ISO-NE-proposed or the NEPOOL-proposed ORTPs for FCA16 would violate the filed rate doctrine or the rule against retroactive ratemaking;[46] and (ii) arguments about the MOPR (as outside the scope of this proceeding). In light of this outcome, the FERC directed ISO-NE to submit a compliance filing on or before June 22, 2021 that combines the alternative proposals as accepted by the FERC.

Compliance filing (-001). The FERC accepted ISO-NE's June 22, 2021 compliance filing on August 10, 2021.[47] As previously reported, the ISO-NE compliance filing (i) submitted Tariff revisions to incorporate the ORTPs and related revisions accepted in the *ORTP Jump Ball Order* (including NEPOOL's proposed ORTP value for battery storage and NEPOOL's proposed federal tax credits adjustments to the ORTPs for PV solar resources for FCA17 and FCA18) and (ii) explained why ISO-NE was not proposing further updates to the FCA16 ORTP values to account for adjustments to CONE and related values for FCA16 in the *Updated CONE, Net Cone and PPR Values Order*. The compliance filing was accepted effective June 8, 2021, as requested. Unless the August 10 order is challenged, activity in this sub-docket will be concluded.

Request for Rehearing of ORTP Jump Ball Order (-002) Denied; ORTP Jump Ball Order Discussion Modified; Result Unchanged. Clean Energy Advocates[48] request for rehearing of the *ORTP Jump Ball Order* was denied by operation of law on August 6, 2021.[49] As is its right under section 313(a) of the FPA, the FERC then later issued an order, on August 26, 2021, modifying the discussion in the *ORTP Jump Ball Order* but reaching the same result.[50] In the *ORTP Jump Ball Allegheny Order*, the FERC explained why it found unpersuasive Clean Energy Advocates' arguments raised on rehearing. Dissenting in part, Chairman Glick and Commission Clements again stated that the FERC should have instead adopted NEPOOL's proposed capital cost estimate for offshore wind resources, finding they "better reflect current market activity compared to ISO-NE's estimates that are based on outdated and proprietary data". Challenges, if any, to the *ORTP Jump Ball Order* and the *ORTP Jump Ball Allegheny Order* must be filed in Federal Court on or before October 25, 2021. If you have any questions concerning this proceeding, please contact Dave Doot (dtdoot@daypitney.com; 860-275-0102), Sebastian Lombardi (860-275-0663; slombardi@daypitney.com), Joe Fagan (202-218-3901; jfagan@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

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

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

[47] *ISO New England Inc.*, Docket No. ER21-1637-001 (Aug. 10, 2021) (unpublished letter order).

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

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

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

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

As previously reported, the FERC conditionally accepted on May 28, 2021,[51] eff. May 29, 2021, the updates to the CONE, Net CONE and PPR values, as amended in ISO-NE's March 30, 2021 Deficiency Response,[52] as well as the modified definition of Net CONE, subject to a compliance filing that reflects the assumption that the reference unit has on-site compression.[53] ISO-NE submitted on June 11, 2021, and the FERC accepted on July 30, 2021,[54] that compliance filing, which updated the CONE, Net CONE and PPR values to $12.400, $7.468 and $9,337, respectively, to reflect the cost of gas compression.

Request for Rehearing Denied by Operation of Law. On July 29, 2021, the FERC issued a "Notice of Denial of Rehearing by Operation of Law and Providing for Further Consideration",[55] in response to the June 28, 2021 joint request by EPSA and NEPGA for rehearing of both the *Updated CONE, Net Cone and PPR Values Order* and the *NEPGA Net Cone Complaint Order*. The Notice confirmed that the 60-day period during which a petition for review of the *Updated CONE, Net Cone and PPR Values Order* can be filed with an appropriate federal court was triggered when the FERC did not act on the requests for rehearing of the *Updated CONE, Net Cone and PPR Values Order*. The Notice also indicated that the FERC would address, as is its right, the rehearing request in a future order, and may modify or set aside its order, in whole or in part, "in such manner as it shall deem proper."

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).

IV. OATT Amendments / TOAs / Coordination Agreements

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

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

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

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

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

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

[55] *New England Power Generators Assoc., Inc. v. ISO New England Inc.*, 176 FERC ¶ 62,059 (July 29, 2021) ("*Notice Denying* by Operation of Law *Reh'g of Updated CONE, Net Cone and PPR Values Order*").

August 6, 2021. Answers to the PTO AC Answer were filed by NEPGA and the IMM on August 13 and August 16, respectively.

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

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

On July 27, 2021, the PTO AC, ISO-NE, Schedule 20A Service Providers, GMP, and VTransco filed revisions to ISO-NE Tariff Schedule 21-Common and Schedule 20A-Common in accordance with *Order 676-I*. The revisions include certain updated business practice standards (Version 003.2) adopted by the Wholesale Electric Quadrant ("WEQ") of the North American Energy Standards Board ("NAESB") and incorporated by reference in the FERC's regulations through *Order 676-I*. Comments on this filing were due on or before August 19, 2021; none were filed. National Grid filed a doc-less intervention on August 13, 2021. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

On July 26, 2021, CSC and ISO-NE filed revisions to ISO-NE Tariff Schedule 18-Attachment Z in accordance with *Order 676-I*. The revisions include certain updated business practice standards (Version 003.2) adopted by NAESB's Wholesale Electric Quadrant and incorporated by reference in the FERC's regulations through *Order 676-I*. Comments on this filing were due on or before August 16, 2021; none were filed. National Grid and CSC filed doc-less interventions on August 13, 2021 and August 16, 2021, respectively. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **ISO-NE/NEPOOL *Order 676-I* Compliance Filing (ER21-941)**

On January 26, 2021, ISO-NE and NEPOOL, in response to *Order 676-I*, jointly filed changes to incorporate by reference in Schedule 24 of the OATT the latest version (Version 003.2) of certain Standards for Business Practices and Communication Protocols for Public Utilities adopted by NAESB's Wholesale Electric Quadrant. The Participants Committee unanimously supported the *Order 676-I* revisions at its May 7, 2020 meeting. Comments on this filing were due on or before February 16, 2021; none were filed. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Changes

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

On August 12, 2021, United Illuminating ("UI") submitted a new Phase I/II HVDC-TF Service Agreement between itself and Vitol Inc. ("Vitol") under Schedule 20A-UI for 1 MW of firm service over the Phase I/II HVDC transmission facilities ("Phase I/II HVDC-TF"). A November 20, 2020 effective date was requested (the date on which monthly firm service began). Comments on this filing are due on or before September 2, 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-CMP: Vitol Phase I/II HVDC-TF Service Agreement (ER21-2661)**

Also on August 12, 2021, Central Maine Power ("CMP") similarly submitted a new Phase I/II HVDC-TF Service Agreement between itself and Vitol under Schedule 20A-CMP for 1 MW of firm service over the Phase I/II HVDC-TF. A November 20, 2020 effective date was requested (the date on which monthly firm service began). Comments on this filing are due on or before September 2, 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 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,*[56] and certified by Settlement Judge Dring[57] to the Commission,[58] 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-VP 2021 Annual Informational Filing (ER20-2119)**

On June 15, 2021, as updated on June 30, 2021, Versant Power submitted its annual informational filing to update its local transmission service charges under Schedule 21-VP. Included in its June 30, 2021 update was a revised version of Attachment P that sets forth the rates that went into effect on June 1, 2021 and reflects a settlement in principle reached with the Maine Public Utilities Commission ("MPUC") regarding charges under Schedule 21-VP for the 2020-2021 rate. Since the last Report, on July 28, 2021, Versant filed a correction to certain of its 12-CP values, which will result in 29% reduction in the $/kW-month rate for Large Power – Transmission Voltage customers and a small increase (if any) in the rates for other retail customers (less than 25 basis points). With the correction and the timing of billing, the large customers will not have to pay incorrect rates; the other retail customers will continue to pay rates as filed in June, subject to a true-up "at the next available opportunity". The FERC will not notice these information filings 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).

- **Schedule 21-FG&E Annual Informational Filing (ER09-1498)**

On July 26, 2021, Fitchburg Gas & Electric ("FG&E") submitted its data and schedules used to calculate its annual transmission revenue requirement for Non-PTF Local Network Transmission Service, Firm Point-to-Point Transmission Service and Non-Firm Point-to-Point Transmission Service as set forth in Schedule 21-FG&E covering the June 1, 2021 – May 31, 2022 period. FG&E reported that its annual revenue requirement

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[56] *Emera Maine and BHE Holdings*, 155 FERC ¶ 61,230 (June 2, 2016) ("*MPS Merger-Related Costs Order*"). In the *MPS Merger-Related Costs Order*, the FERC accepted, but established hearing and settlement judge procedures for, filings by Emera Maine seeking authorization to recover certain merger-related costs viewed by the FERC's Office of Enforcement's Division of Audits and Accounting ("DAA") to be subject to the conditions of the orders authorizing Emera Maine's acquisition of, and ultimate merger with, Maine Public Service ("Merger Conditions"). The Merger Conditions imposed a hold harmless requirement, and required a compliance filing demonstrating fulfillment of that requirement, should Emera Maine seek to recover transaction-related costs through any transmission rate. Following an audit of Emera Maine, DAA found that Emera Maine "inappropriately included the costs of four merger-related capital initiatives in its formula rate recovery mechanisms" and "did not properly record certain merger-related expenses incurred to consummate the merger transaction to appropriate non-operating expense accounts as required by [FERC] regulations [and] inappropriately included costs of merger-related activities through its formula rate recovery mechanisms" without first making a compliance filing as required by the merger orders. The *MPS Merger-Related Costs Order* set resolution of the issues of material fact for hearing and settlement judge procedures, consolidating the separate compliance filing dockets.

[57] ALJ John Dring was the settlement judge for these proceedings. There were five settlement conferences -- three in 2016 and two in 2017. With the Settlement pending before the FERC, settlement judge procedures, for now, have not been terminated.

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

reflected in FG&E's rates effective June 1, 2021, is $1,439,133. 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).

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

The TOs' November 2, 2015 refund report documenting resettlements of regional transmission charges by ISO-NE in compliance with *Opinions No. 531-A*[59] *and 531-B*[60] also remains pending. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

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

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

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

- **Capital Projects Report - 2021 Q2 (ER21-2632)**

On August 9, 2021, ISO-NE filed its Capital Projects Report and Unamortized Cost Schedule covering the second quarter of calendar year 2021 (the "Report"). ISO-NE is required to file the Report under Section 205 of the FPA pursuant to Section IV.B.6.2 of the Tariff. Report highlights included the following new projects: (i) Forward Capacity Tracking System Infrastructure Conversion Part III ($3.15 million); (ii) FCM Cost Allocation & Accelerated Billing ($1.065 million); (iii) Enterprise Application Integration Phase II ($958,000); (iv) nGEM Hardware Phase I ($872,900); (v) Oracle 19c Upgrade ($653,000); (vi) Replacement of LMP Monitor ($383,800); (vii) Secure Lightweight Directory Access Protocol Channel Binding Adaptation ($294,400); (viii) Market Information System ("MIS") File Transfer Protocol ("FTP") Refresh ($155,000); Single Sign-on Technology Upgrade ($150,000). Projects with a significant changes (with amounts returned to the Emerging Work Fund following in parentheses) were (i) Communications Front End Energy Management Platform ("EMP") 3.2 Upgrade ($172,900); (ii) Sub-Accounts for FTR Market ($155,000); (iii) CIP Electronic Security Perimeter Redesign ($149,900); (iv) PI Historian for Short-term m Phasor Measurement Units ("PMU") Data Repository ($134,300); (v) FCM Qualification Enhancements ($120,000); and (vi) Capital Projects in Planning/Conceptual Design (e Human Resources Workflow & Document Management and ESI projects) ($299,200). Comments on this filing were due on or before August 30, 2021. On August 16, NEPOOL filed comments supporting the filing. Eversource and National Grid filed doc-less interventions. This matter is

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

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

pending before the FERC. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **Interconnection Study Metrics Processing Time Exceedance Report Q2 2021 (ER19-1951)**

On August 13, 2021, ISO-NE filed, as required,[61] public and confidential[62] versions of its Interconnection Study Metrics Processing Time Exceedance Report (the "Exceedance Report") for the second quarter of 2021 ("2021 Q2"). ISO-NE reported that one of the three 2021 Q2 ***Interconnection Feasibility Study ("IFS") reports*** delivered to Interconnection Customers were delivered later than the best efforts completion timeline.[63] In addition, three IFS Report that has not yet been completed has exceeded the 90-day completion expectation. The average time from ISO-NE's receipt of the executed IFS Agreement to delivery of the completed IFS report to the Interconnection Customer was 92.33 days (down from 115.4 in 2021 Q1). Four of the five ***System Impact Study ("SIS") reports*** delivered to Interconnection Customers were delivered later than the best efforts completion timeline of 270 days. The average time from ISO-NE's receipt of the executed SIS Agreement to delivery of the completed SIS report to the Interconnection Customer was 475 days (up from 434 in 2021 Q1). In addition, 12 SIS reports that are not yet completed have exceeded the 270-day completion expectation. Section 4 of the Report identified steps ISO-NE has identified to remedy issues and prevent future delays, including mitigating the impact of backlogs and initiating clustering, moving to earlier in the process certain Interconnection Customer data reviews, and enhanced information sharing and coordination efforts with Interconnecting TOs. This report will not be noticed for public comment.

- **IMM Quarterly Markets Reports – Spring 2021 (ZZ21-4)**

On August 6, 2021, the IMM filed with the FERC its Spring 2021 report of "market data regularly collected by [the IMM] in the course of carrying out its functions under … Appendix A and analysis of such market data," as required pursuant to Section 12.2.2 of Appendix A to Market Rule 1. These filings are not noticed for public comment by the FERC. The Spring 2021 Report will be discussed at an upcoming Markets Committee meeting.

- **ISO-NE FERC Form 3Q (2021/Q2) (not docketed)**

On August 30, 2021, ISO-NE submitted its 2021/Q2 FERC Form 3Q (Quarterly financial report of electric utilities, licensees, and natural gas companies). FERC Form 3-Q is a quarterly regulatory requirement which supplements the annual FERC Form 1 financial reporting requirement. These filings are not noticed for comment.

IX. Membership Filings

- **September 2021 Membership Filing (ER21-2802)**

On August 30, 2021, NEPOOL requested that the FERC accept (i) the memberships of Gravel Pit Solar, LLC [Related Person to DWW Solar II and Fusion Solar Center, LLC (AR Sector, Large RG Group Member)]; Tyr Energy (Supplier Sector); and Walden Renewables Development LLC (Provisional Member); and (ii) the termination of the Participant status of: Brookfield Energy Marketing Inc. [Related Person to Brookfield companies (Supplier Sector)];

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[61] 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.

[62] 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.

[63] 90 days from the Interconnection Customer's execution of the study agreement.

and HIKO Energy and Perigee Energy [Related Persons to Spark Energy (Supplier Sector)]. Comments on this filing are due on or before September 21, 2021.

- **August 2021 Membership Filing (ER21-2552)**

On July 28, 2021, NEPOOL requested that the FERC accept (i) the memberships of In Commodities US LLC (Supplier Sector); and Jupiter Power (Provisional Member); (ii) the termination of the Participant status of GenOn Energy Management and GenOn Canal; and (iii) the name change of Rivercrest Power-SOUTH, LLC (f/k/a BioUrja Power LLC). Comments on this filing were due on or before August 19, 2021; none were filed. This matter is pending before the FERC.

- **July 2021 Membership Filing (ER21-2267)**

On August 25, 2021, the FERC accepted (i) the memberships of Gridmatic Isotria LLC (Supplier Sector); InBalance, Inc. (Supplier Sector); North East Offshore, LLC [Related Person to Deepwater Wind and Eversource]; and NEPGA (Fuels Industry Participant); (ii) the termination of the Participant status of Priogen Power LLC; and (iii) the name change of WP&G Holdings, LLC (f/k/a Mega Energy Holdings, LLC).[64] Unless the August 24 order is challenged, this proceeding will be concluded.

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

Questions concerning any of the ERO Reliability Standards or related rule-making proceedings or filings can be directed to Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Revised Reliability Standards (Cold Weather Reliability Standards): EOP-011-2; IRO-010-4; and TOP-003-5 (RD21-5)**

On August 24, 2021, the FERC approved changes to the following Reliability Standards to require generators to implement plans for cold weather preparedness and to enhance the ability of Balancing Authorities, Transmission Operators and Reliability Coordinators to plan and operate the grid reliably during cold weather conditions by requiring the exchange of information related to generators' capability to operate ("together, the "Cold Weather Reliability Standards"):[65]

- ♦ EOP-011-2 (Emergency Preparedness and Operations)
- ♦ IRO-010-4 (Reliability Coordinator Data Specification and Collection)
- ♦ TOP-003-5 (Operational Reliability Data)

The Cold Weather Reliability Standards address recommendations arising from FERC and NERC Staff's report on the causes of the January 17, 2018 cold weather event affecting the south central United States. The revised Reliability Standards will become effective (and the currently effective versions will be retired) on April 1, 2023, or the first day of the first calendar quarter that is 18 months following FERC approval.

- **Revised Reliability Standards (SOL Changes): FAC-003-5, 011-4, 014-3; IRO-008-3; PRC 002-3, 023-5, -026-2; and TOP-001-6 (RM21-19)**

On June 28, 2021, NERC filed for approval proposed changes to the following Reliability Standards related to establishing and communicating System Operating Limits ("SOLs", and together the "SOL Changes"):

- ♦ FAC-011-4 (System Operating Limits Methodology for the Operations Horizon)
- ♦ FAC-014-3 (Establish and Communicate System Operating Limits)
- ♦ FAC-003-5 (Transmission Vegetation Management)
- ♦ IRO-008-3 (Reliability Coordinator Operational Analyses and Real-time Assessments)

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[64] *New England Power Pool Participants Comm*., Docket No. ER21-2667 (Aug. 25, 2021).

[65] *N. Amer. Elec. Rel. Corp.*, 176 FERC ¶ 61,119 (Aug. 24, 2021).

- ♦ PRC-002-3 (Disturbance Monitoring and Reporting Requirements)
- ♦ PRC-023-5 (Transmission Relay Loadability)
- ♦ PRC-026-2 (Relay Performance During Stable Power Swings)
- ♦ TOP-001-6 (Transmission Operations)

NERC also requested the retirement of Reliability Standard FAC-010-3 (System Operating Limits Methodology for the Planning Horizon) and modifications to NERC's Glossary of Terms to revise the definition for System Operating Limit and to include "System Voltage Limit". The SOL Changes (NERC Project 2015-09) were developed in response to recommendations from a periodic review of the FAC-010, FAC-011, and FAC-014 Reliability Standards. NERC asked that revised Reliability Standards become effective (and the currently effective versions be retired) on the first day of the first calendar quarter that is 24 months following FERC approval. The SOL Changes have not yet been noticed for public comment.

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

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

Comments were filed by NERC, the ISO/RTO Council ("IRC"), APPA/LPPC, Canadian Electricity Assoc. ("CEA"), Cogentrix, EEI/EPSA, Forescout Technologies, MISO TOs, NJ BPU, NRECA, Reliable Energy Analytics, Southwestern Power Administration, SEIA, Siemen's Energy, Southern Companies, TAPS, U.S. Bureau of Reclamation, U.S Corp of Army Engineers, Western Area Power Administration ("WAPA"), Wolverine Power Supply Cooperative, XTec, and J. Applebaum, J. Christopher/T. Conway, and 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.[66] On March 25, 2020, Joint Associations[67] requested an extension of time to submit comments and reply comments. On April 2, the FERC granted Joint Associations' request and extended the deadline for initial comments on the NOI to July 1, 2020; the deadline for reply comments, July 31, 2020. Comments were filed by NERC, the IRC, Accenture, Amazon Web Services ("Amazon"), Bonneville, the Bureau of Reclamation, Barry Jones, Georgia System Operations, GridBright, Idaho Power, Microsoft, MISO, MISO Transmission Owners, Siemens Energy Management, Tri-State Generation and Transmission Association, VMware, Inc., AEE, American Association for Laboratory Accreditation ("A2LA"), APPA, Canadian Electricity Assoc., EEI, NRECA, and Waterfall Security Solutions. Reply comments were due on or before July 31, 2020, and were filed by AEE, Amazon and Microsoft.

In part in response to the comments filed, the FERC, in a December 17, 2020 order,[68] directed NERC to begin a formal process to assess, and to make an informational filing in a little over one year (January 1, 2022) that

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

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

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

addresses, the feasibility of voluntarily conducting BES operations in the cloud in a secure manner, as well as the status and schedule for any plans to modify the standards.

- ***Order 873*** **- Retirement of Reliability Standard Requirements (Standards Efficiency Review) (RM19-17; RM19-16)**

On September 17, 2020, the FERC approved the retirement of the 18 Reliability Standard requirements through the retirement of four Reliability Standards and the modification of five Reliability Standards,[69] concluding that the 18 requirements "(1) provide little or no reliability benefit; (2) are administrative in nature or relate expressly to commercial or business practices; or (3) are redundant with other Reliability Standards."[70] The FERC also approved the associated violation risk factors, violation severity levels, implementation plan, and effective dates proposed by NERC. Because it was not persuaded by NERC's justification for the retirement of FAC-008-4 requirement R8, the FERC remanded the retirement of requirements R7 and R8 to NERC for further consideration.[71]

The FERC left for another day its final action on the remaining 56 requirements for which the FERC proposed to approve retirement in the *Retirements NOPR*[72] (the "MOD A Reliability Standards"). The FERC intends to coordinate the effective dates for the retirement of the MOD A Reliability Standards with successor North American Energy Standards Board ("NAESB") business practice standards (v. 003.3) that include Modeling business practices, which were just accepted in *Order 676-J* (*see* Section XII below).

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

On August 24, 2021, NERC submitted its proposed Business Plan and Budget, as well as the Business Plans and Budgets for the Regional Entities, including NPCC, for 2022. FERC regulations[73] require NERC to file its proposed annual budget for statutory and non-statutory activities 130 days before the beginning of its fiscal year (January 1), as well as the annual budget of each Regional Entity for their statutory and non-statutory activities, including complete business plans, organization charts, and explanations of the proposed collection of all dues, fees and charges and the proposed expenditure of funds collected. NERC reports that its proposed 2022 funding requirement represents an overall increase of approximately 6.2% over NERC's 2021 funding requirement. The NPCC U.S. allocation of NERC's net funding requirement is $9.44 million. NPCC has requested $17.5 million in statutory funding (a U.S. assessment per kWh (2020 NEL) of $0.0000540) and $1 million for non-statutory functions. Comments on this filing are due on or before September 14, 2021.

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[69] *Elec. Rel. Org. Proposal to Retire Reqs. in Rel. Standards Under the NERC Standards Efficiency Review*, Order No. 873, 172 FERC ¶ 61,225 (Sep. 17, 2020) ("*Order 873*"). The four Reliability Standards being eliminated in their entirety are FAC-013-2 (Assessment of Transfer Capability for the Near-term Transmission Planning Horizon), INT-004-3.1 (Dynamic Transfers), INT-010-2.1 (Interchange Initiation and Modification for Reliability), MOD-020-0 (Providing Interruptible Demands and Direct Control Load Management Data to System Operations and Reliability Coordinators). The five modified Reliability Standards are INT-006-5 (Evaluation of Interchange Transactions), INT-009-3 (Implementation of Interchange) and PRC-004-6 (Protection System Misoperation Identification and Correction), IRO-002-7 (Reliability Coordination—Monitoring and Analysis), TOP-001-5 (Transmission Operations).

[70] *Order 873* at P 2.

[71] *Order 873* at P 5. Pursuant to FPA section 215(d)(4), if the FERC disapproves a modification to a Reliability Standard in whole or in part, it must remand the entire Reliability Standard to NERC for further consideration. Accordingly, although it was satisfied here with the justification for the retirement of R7, the FERC was required to remand both R7 and R8 so that its concerns with the retirement of Requirement R8 could be addressed.

[72] *Electric Reliability Organization Proposal to Retire Requirements in Rel. Standards Under the NERC Standards Efficiency Review*, 170 FERC ¶ 61,032 (Jan. 23, 2020) ("*Retirements NOPR*") (proposing to approve the retirement of 74 of 77 Reliability Standard requirements requested to be retired by NERC in these two dockets in connection with the first phase of work under NERC's Standards Efficiency Review, an initiative begun in 2017 that reviewed the body of NERC Reliability Standards to identify those Reliability Standards and requirements that were administrative in nature, duplicative to other standards, or provided no benefit to reliability). As previously reported, NERC withdrew its proposed changes to VAR-001-6 on May 14, 2020, reducing to 76 the number of requirements proposed to be retired.

[73] 18 CFR § 39.4(b) (2014).

- **Rules of Procedure Changes (Reliability Standards Development Revisions) (RR21-8)**

On August 18, 2021, NERC filed for approval revisions to sections 300 (Reliability Standards Development), Appendix 3B (Procedure for Election of Members of the Standards Committee) and Appendix 3D (Development of Registered Ballot Body Criteria) of the NERC Rules of Procedure ("ROP"), which are designed to update language, staff titles, and processes; remove unnecessary or duplicative obligations; and clarify roles and responsibilities related to the development of Reliability Standards (the "Reliability Standards Development ROP Revisions"). Comments on this filing are due on or before September 8, 2021.

- **Report of Comparisons of 2020 Budgeted to Actual Costs for NERC and the Regional Entities (RR21-5)**

On June 1, 2021, NERC filed comparisons of actual to budgeted costs for 2020 for NERC and the six Regional Entities operating in 2020, including NPCC. The Report includes comparisons of actual funding received and costs incurred, with explanations of significant actual cost-to-budget variances, audited financial statements, and tables showing metrics concerning NERC and Regional Entity administrative costs in their 2020 budgets and actual results. Comments on this filing were due on or before June 22, 2021; none were filed. This matter is pending before the FERC.

- **5-Year ERO Performance Assessment Report (RR19-7-002)**

On August 17, 2021, the FERC accepted NERC's further compliance filing[74] in response to the requirements of the January 19, 2021 *Order on Compliance Filings.*[75] The further compliance filing (i) further clarified information sharing between NERC and the Electricity Information Sharing and Analysis Center[76] ("E-ISAC") as it relates to the development of Reliability Standards; and (ii) revised NERC's Rules of Procedure to explicitly require that NERC share all Points Bulletins ("APBs") with the FERC no later than at the time of issuance. Unless the August 17 order is challenged, this proceeding will be concluded.

- **SolarWinds and Related Supply Chain Compromise White Paper (not docketed)**

On July 7, 2021, FERC staff and E-ISAC released a joint white paper emphasizing the need for continued vigilance by the electricity industry related to supply chain compromises and incidents and recommending specific cybersecurity mitigation actions to better ensure the security of the bulk-power system ("BPS"). View the Report here.

- **FERC/NERC Joint Report on Real Time Assessments (not docketed)**

On July 8, 2021, FERC Staff, together with staff from NERC and its regional entities issued a report outlining recommendations for real-time assessments of grid operating conditions.[77] The report concluded that system operators are prepared to manage limited impairments of their primary assessment tools or data through system redundancy and redundant data sources. However, infrequent events involving significant real-time data loss or the failure of primary analysis tools lasting more than two hours require the development of alternative data sources, tools, and analyses work to mitigate the potential loss of visibility and control resulting from the impairment of their primary tools. The report addressed the following seven technical areas related to real-time assessments, including observations, conclusions, and recommendations for each: (i) Real-time Assessment Tools

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[74] *N. Am. Elec. Rel. Corp.*, Docket No. RR19-7-002 (Aug. 17, 2021) (unpublished letter order).

[75] *N. Am. Elec. Rel. Corp.*, 174 FERC ¶ 61,030 (2021) ("*Order on Compliance Filings*") (accepting NERC's compliance filings submitted in response the FERC's *2020 Five Year Order* (*N. Am. Elec. Rel. Corp.*, 170 FERC ¶ 61,029 (Jan. 23, 2020)) and directing the further compliance filing).

[76] The EISAC, created in 1999 pursuant to a U.S. presidential directive, provides its member utilities and partners with resources to prepare for and reduce cyber and physical security threats to the North American electricity industry

[77] Real-time assessments evaluate system conditions using real-time data to measure existing and potential operating conditions to ensure continued reliable operation of the bulk electric system. The joint staff review focuses on strategies and techniques used by reliability coordinators and transmission operators to perform these assessments following a loss or degradation of data or tools used to maintain situational awareness. The review included on-site discussions with representatives of nine participating reliability coordinators and transmission operators.

Under Normal Operating Conditions; (ii) Real-time Data and Data Quality; (iii) Real-time Data Loss Management; (iv) Alternative Real-time Assessment and Study Tools; (v) Model Management; (vi) Control Center Hardware Configuration; and (vii) Major System Upgrades/Vendor Changes. View the Report here.

XI. Misc. - of Regional Interest

- **203 Application: Valcour Wind Energy/AES (EC21-114)**

On August 13, 2021, Valcour Wind Energy, LLC ("Valcour") and AES Corporation, among others, requested authorization for a transaction pursuant to which Valcour will become, ultimately, a Related Person of AES. Consummation of this transaction will make Valcour Wind Energy and AES Distributed Energy, Inc. Related Persons. Comments on this filing are due on or before September 3, 2021. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On August 11, 2021, Covanta Holding Corporation, on behalf of and together with its public utility subsidiaries, including NEPOOL member Covanta Energy Marketing, LLC ("Covanta"), requested authorization for a transaction pursuant to which Covanta will become a wholly-owned subsidiary Covert Intermediate, Inc., itself an indirectly, wholly-owned affiliate of EQT AB ("EQT"). Consummation of this and the Cypress Creek Holdings transaction summarized just below, will make Covanta and Cypress Creek Renewables Related Persons. Comments on this filing were due on or before September 1, 2021. Thus far, a doc-less intervention by the PJM IMM has been posted. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Cypress Creek/EQT (EC21-108)**

On July 27, 2021, Cypress Creek Holdings, LLC, on behalf of and together with its public utility subsidiaries, including NEPOOL member Cypress Creek Renewables, LLC ("Cypress Creek"), requested authorization for a transaction pursuant to which Cypress Creek will become a wholly-owned subsidiary Catalyst AcquisitionCo, Inc. ("Catalyst"), itself an indirectly, wholly-owned affiliate of EQT. Consummation of this and the Covanta transaction summarized just above, will make Cypress Creek Renewables and Covanta Energy Marketing Related Persons. Comments on this filing were due on or before August 17, 2021; none were filed. Doc-less interventions were filed by Catalyst and the PJM IMM. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: PPL/Narragansett (EC21-87)**

On May 4, 2021, PPL Corporation and The Narragansett Electric Company ("Narragansett") requested authorization for a transaction pursuant to which a wholly-owned subsidiary of PPL will acquire 100% of the outstanding shares of common stock of Narragansett. The transaction is expected to close in the fourth quarter of 2021. Since the last Report, the Rhode Island ("RI") Division of Public Utilities and Carriers ("RI DPU") and RI Attorney General intervened out-of-time and filed comments. On July 7, PPL and Narragansett jointly answered the RI AG comments. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Seneca/Rice et al. (EC21-84)**

On June 14, 2021, the FERC authorized a transaction pursuant to which the ultimate upstream ownership of Seneca Energy II ("Seneca"), among others, will change to include a publicly listed company (Rice Acquisition Corp. ("Rice")) and both Aria Energy LLC ("Aria"), which is wholly-owned by funds managed by Ares Management Corporation ("Ares Management"), and Archaea Energy, LLC ("Archaea").[78] After the closing, Aria affiliates will hold approximately 20% of the expected outstanding voting shares; Archaea and its members, 29%; Rice and its

[78] *Seneca Energy, II LLC et al.*, 175 FERC ¶ 62,170 (June 14, 2021).

shareholders, the remaining shares. Seneca will remain, for the time being, a Related Person to Generation Sector member Kleen Energy. Pursuant to the June 14 order, notice must be filed within 10 days of consummation of the transaction, which as of the date of this Report has not yet occurred. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: NRG/Generation Bridge (ArcLight) (EC21-74)**

On August 18, 2021, the FERC authorized a transaction pursuant to which 100% of the membership interest in certain NRG Project Companies[79] will be sold to Generation Bridge Acquisition, LLC ("Purchaser"), a wholly-owned, indirect subsidiary of ArcLight Fund VI, which is itself affiliated with Great River Hydro.[80] This matter is pending before the FERC. Pursuant to the August 18 order, notice must be filed within 10 days of consummation of the transaction, which as of the date of this Report has not yet occurred. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Exelon Generation (EC21-57)**

On August 24, 2021, the FERC authorized a "spin" transaction in which, after completion of an internal reorganization, the ownership of the public utility subsidiaries ("ExGen Utility Subsidiaries") of Exelon Generation Company, LLC ("ExGen") intermediate holding company owner, HoldCo, will be distributed to the shareholders of Applicants' current ultimate upstream owner, Exelon Corporation (the "Transaction").[81] Following the Transaction, Exelon Corporation and its remaining subsidiaries will retain no interest in or affiliation with ExGen or the ExGen Utility Subsidiaries; Exelon Corporation and HoldCo will be separate publicly-traded companies. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **TSAs: Third Amendments to NECEC Transmission TSAs (ER21-2738 et al.)**

On August 23, 2021, NECEC Transmission filed executed third amendments to 7 of its previously-filed and accepted, cost-based transmission service agreements ("TSAs") with the participants that will fund the construction, operation and maintenance of the New England Clean Energy Connect Project.[82] The amendments are intended to (i) clarify the scope of the NECEC Project, specifically the Network Upgrades needed to interconnect the project to the New England Transmission System, based on the results of the applicable ISO-NE system impact studies; and (ii) allow NECEC Transmission to certify achievement of certain critical milestones related to construction authorizations and other approvals from governmental organizations and ISO-NE, based on the clarified scope. An August 24, 2021 effective date was requested. Comments on the third amendments are due on or before September 13, 2021. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Seabrook/NECEC E&P Agreement (ER21-2719)**

On August 19, NextEra Energy Seabrook, LLC ("Seabrook") filed an Engineering & Procurement Agreement ("E&P Agreement") between itself and NECEC Transmission, LLC. The E&P Agreement (designated as Seabrook Rate Schedule No. 2) provides the terms and conditions "concerning the engineering and procurement of long lead-time items" associated with work to be engaged in by Seabrook at NECEC's request "for the design, engineering, planning, permitting, and procurement of material and equipment" necessary to address the Significant Adverse Impact on Seabrook. Seabrook reported that all of the terms and conditions of the E&P Agreement have been mutually agreed upon. An August 20, 2021 effective date was requested.

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[79] The New England "NRG Project Companies" are Connecticut Jet Power LLC ("Connecticut Jet"), Devon Power LLC ("Devon"), Middletown Power LLC ("Middletown"), and Montville Power LLC ("Montville").

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

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

[82] The third amendments to the 7 TSAs were separately docketed as follows: Eversource (ER21-2738); National Grid (ER21-2739); Unitil (ER21-2742); HQUS/Eversource (ER21-2743); HQUS/National Grid (ER21-2744); HQUS/Unitil (ER21-2745); and HQUS Additional (ER21-2747).

Comments on this filing are due on or before September 9, 2021. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **ISA: NSTAR/Servistar (ER21-2696)**

On August 16, 2021, NSTAR filed an interconnection study agreement ("ISA") between itself and Servistar LLC ("Servistar"). Servistar is proposing to interconnect a 150 MW data center facility to Eversource's 1293 and 1302 115 kV transmission lines (ISO-NE queue position #1140). The ISA sets forth the terms and conditions under which NSTAR will study the feasibility of the project's interconnection ahead of the commencement of the ISO-NE study to give a preliminary review of possible adverse impacts to the system which the project will be responsible to mitigate. Comments on the ISA are due on or before September 7, 2021. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement: NSTAR/Medway Grid II (ER21-2684)**

On August 16, 2021, NSTAR filed a second D&E Agreement between itself and Medway Grid, LLC ("Medway"). The second Medway D&E Agreement sets forth the terms and conditions under which NSTAR will undertake certain preliminary design and engineering activities related to the upgrades identified in the System Impact Study for queue position #844, Medway's request to interconnect to NSTAR's 3445 kV West Medway Substation. Comments on the NSTAR/Medway Grid II D&E Agreement are due on or before September 7, 2021. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **LGIA: National Grid / New England Wind (Hoosac) (ER21-2548)**

On July 29, 2021, National Grid and ISO-NE ("Filing Parties") filed a First Revised LGIA between the Filing Parties and New England Wind to include details regarding the Direct Assignment Facilities charge omitted from the original LGIA and to update the Capacity Network Resource Capability ("CNRC") of the 28.5 MW Hoosac wind farm. Going forward, the Filing Parties will report the conforming First Revised LGIA in their respective Electric Quarterly Reports. A March 19, 2021 effective date (the date the revised LGIA was signed) was requested. Comments on this filing were due on or before July 19, 2021; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Versant Power MPD OATT *Order 676-I* Compliance Filing (ER21-2498)**

On July 23, 2021, Versant Power filed proposed revisions to Section 4 of the Versant Power Open Access Transmission Tariff For Maine Public District (the "MPD OATT") to incorporate by reference certain of the revisions required by *Order 676-I* and requested waiver of certain of those standards that are not applicable to MPD and/or the MPD OATT. Comments on this filing were due on or before August 13, 2021; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Versant Waiver Request: Unreserved Transmission Use Penalty Policy (ER21-2447)**

On July 16, 2021, Versant Power requested a limited waiver of the application of its posted policy statement regarding penalties for unreserved transmission use that was in effect from January through March 2021 to Black Bear SO, LLC and Black Bear Hydro Partners, LLC (jointly, "Black Bear"). Instead, Versant proposes to charge Black Bear penalties for unreserved use based on Versant Power's revised policy statement as published May 11, 2021, avoiding the imposition of a penalty on Black Bear that is nearly seven times what it would have incurred had it reserved and scheduled annual or monthly transmission service appropriately, but still requiring Black Bear to pay an unreserved use penalty for service used without the appropriate reservations. Comments on Versant's waiver request were due on or before August 6, 2021. Black Bear filed comments on August 6, 2021. Versant answered Black Bear's comments on August 11, 2021.

This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement: NSTAR/Hingham Municipal Light Plant (ER21-2281)**

On August 20, 2021, the FERC accepted an Agreement for Design, Engineering and Construction services (the "D&E Agreement") between NSTAR and Hingham Municipal Light Plant ("Hingham").[83] As previously reported, the D&E Agreement sets forth the terms and conditions under which NSTAR would undertake certain design and engineering activities for the construction of a new 115 kV station to permit NSTAR's Line #478-502 to be sectionalized and Hingham's Hobart Street Substation to be serviced to address a reliability concern for the town of Hingham. The D&E Agreement was accepted for filing as of July 1, 2021, as requested. Unless the August 20 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement: NSTAR/Medway Grid I (ER21-2273)**

On August 26, 2021, the FERC accepted the D&E Agreement between NSTAR and Medway Grid, LLC ("Medway").[84] The Medway D&E Agreement sets forth the terms and conditions under which NSTAR would undertake certain preliminary design and engineering activities related to Qualified Transmission Upgrades identified in the FCA15 Post-Auction Overlapping Impact Restudy for Medway's request to interconnect to NSTAR's 3445 kV West Medway Substation (queue position #844). The Agreement was accepted for filing effective as of July 1, 2021, as requested. Unless the August 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).

- **Amended and Restated IRH Support and Use Agreements eTariff Compliance Filings (ER21-2163 et al.)**

As noted above, in its May 20, 2021 order[85] approving the settlement that amended and restated four Support Agreements and an Agreement with Respect to Use of Québec Interconnection ("Use Agreement"),[86] the FERC directed the Filing Parties[87] to make a compliance filing with revised tariff records in eTariff format reflecting the FERC's action. The Filing Parties submitted their respective compliance filings with revised tariff records in eTariff format on June 18, 2021 (IRH Management Committee (Use Agreement) (ER21-2163); National Grid Asset Owners (Phase I New Hampshire Transmission Line Support Agreement) (ER21-2162); New England Hydro Transmission Corporation (Phase II New Hampshire Transmission Facilities Support Agreement) (ER21-2161); New England Hydro Transmission Electric Company (Phase II Massachusetts Transmission Facilities Support Agreement) (ER21-2160); and VETCO (Phase I Vermont Transmission Line Support Agreement) (ER21-2158)). On August 4, VETCO submitted an errata filing to correct a small number of non-substantive, technical errors in its June 18, 2021 compliance filing.

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[83] *NSTAR Electric Co.*, Docket No. ER21-2281 (Aug. 20, 2021) (unpublished letter order).

[84] *NSTAR Electric Co.*, Docket No. ER21-2273 (Aug. 26, 2021) (unpublished letter order).

[85] *New England Hydro-Transmission Electric Company, Inc. et al.*, 175 FERC ¶ 61,140 (May 20, 2021).

[86] The Support Agreements are separate contracts between the IRH and each of the Asset Owners under which the IRH agree to financially support the elements of the Phase I/II HVDC-TF owned by each Asset Owner in exchange for rights to use the transmission capacity of the Phase I/II HVDC-TF to transmit power to and from the HQ system ("Use Rights"). The Use Agreement is a contract among the IRH that provides the rules for the exercise of the Use Rights, for making the Use Rights available to others, and for the collective management of those individual contractual rights through the IRH Management Committee. The term of the Support Agreements (and thereby the Use Agreement) was extended for another 20 years, until October 31, 2040.

[87] "Filing Parties" were the 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").

On August 17 and 18, 2021, the FERC issued orders accepting all but the VETCO Phase I Vermont Transmission Line Support Agreement,[88] which due to the August 4 errata filing, is still pending before the FERC. Pending action on the VETCO filings, this proceeding will be concluded. If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

In accordance with *Order 864*[89] and *Order 864-A,*[90] and extensions of time granted, New England's public utilities with transmission have submitted their *Order 864* compliance filings, with the specific dockets and filing dates identified in the following table (all remain pending):

Date Filed	Docket	Transmission Provider	Date Accepted
Mar 11, 2021	ER21-1325	NHT	pending
Mar 8, 2021	ER21-1295	Eversource (CL&P, PSNH, NSTAR)	pending
Feb 16, 2021	ER21-1154	Fitchburg Gas & Electric ("FG&E")	pending
Oct 30, 2020 Apr 16, 2021	ER21-311 ER21-1694	Green Mountain Power	pending pending
Aug 5, 2020	ER20-2614	New England Power AC Support Agreement	pending
Aug 5, 2020	ER20-2610	CL&P	pending
Aug 5, 2020	ER20-2609 ER21-1650	NSTAR	pending pending
Aug 5, 2020	ER20-2608	PSNH	pending
Aug 4, 2020	ER20-2607	NEP – Seabrook Transmission Support Agreement	pending
Jul 31, 2020	ER20-2594 ER21-1709	VTransco	pending pending
Jul 30, 2020	ER20-2572 ER21-1130	New England TOs	pending
Jul 30, 2020	ER20-2553	NEP – LSA with MECO/Nantucket	pending
Jul 30, 2020	ER20-2551	New England Power	pending
Jul 15, 2020	ER20-2429 ER21-1702	CMP	pending pending
Jun 29, 2020	ER20-2219	New England Power	pending
Jun 23, 2020 Mar 22, 2021	ER20-2133 -001	Versant Power	pending
May 18, 2020 Jan 7, 2021	ER20-1839	VETCO	pending

[88] *See IRH Management Committee*, Docket No. ER21-2163 (Aug. 18, 2021) (unpublished letter order) (accepting Use Agreement); *New England Elec. Transmission Corp.*, Docket No. ER21-2162 (Aug. 18, 2021) (unpublished letter order) (accepting Phase I New Hampshire Transmission Line Support Agreement); *New England Hydro-Transmission Corp.*, Docket No. ER21-2161 (Aug. 17, 2021) (unpublished letter order) (accepting Phase II New Hampshire Transmission Facilities Support Agreement); and *New England Hydro-Transmission Elec. Co., Inc.*, Docket No. ER21-2160 (Aug. 17, 2021) (unpublished letter order) (accepting Phase II Massachusetts Transmission Facilities Support Agreement).

[89] *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.

[90] *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*").

Feb 26, 2020 Dec 11, 2020	ER20-1089	New England Elec. Trans. Corp.	pending
Feb 26, 2020 Dec 11, 2020	ER20-1088	New England Hydro Trans. Elec. Co.	pending
Feb 26, 2020 Dec 11, 2020	ER20-1087	New England Hydro Trans. Corp.	pending

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

♦ ***ER20-2614-001 (National Grid)***. On August 27, 2021, National Grid filed revisions to provide greater clarity or transparency to its Phase II Facilities AC Support Agreement *Order 864* compliance filing.

♦ ***ER20-2610-001 (CL&P)***. On August 26, 2021, CL&P filed limited revisions to provide greater clarity or transparency to its Millstone TSA *Order 864* compliance filing.

♦ ***ER20-2609-001 (NSTAR)***. On August 26, 2021, NSTAR filed limited revisions to provide greater clarity or transparency to its Phase II Boston Edison AC Facilities Support Agreement *Order 864* compliance filing.

♦ ***ER20-2608-001/2607-001 (PSNH, Seabrook)***. August 20, 2021, PSNH and National Grid submit limited revisions to provide greater clarity or transparency to their previously-submitted Seabrook TSA *Order 864* compliance filings.

XII. Misc. - Administrative & Rulemaking Proceedings

- **Joint Federal-State Task Force on Electric Transmission (AD21-15)**

On June 17, 2021,the FERC established a Joint Federal-State Task Force on Electric Transmission ("Transmission Task Force").[91] The Transmission Task Force will be comprised of all FERC Commissioners as well as representatives from 10 state commissions (two from each NARUC region). State commission representatives will serve one-year terms from the date of appointment by FERC and in no event will serve on the Task Force for more than three consecutive terms. The Transmission Task Force will convene multiple formal meetings annually, with FERC issuing orders fixing the time and place and agenda for each meeting, and will be open to the public for listening and observing and on the record. The Transmission Task Force will focus on "topics related to efficiently and fairly planning and paying for transmission, including transmission to facilitate generator interconnection, that provides benefits from a federal and state perspective."[92] On July 19, 2021, NARUC nominated the 10 state commissioners to the Transmission Task Force, including New England Commissioners Riley Allen (VT PUC) and Matt Nelson (Chair, MA DPU).

On August 30, 2021, the FERC issued an order listing the 10 state commissioner members (confirming the nominations of Commissioner Allen and Chairman Nelson), announcing the first public meeting of the Task Force (to be held Wednesday, November 10, 2021, from approximately 1:00 pm to 6:00 p.m., in Louisville, Kentucky, in conjunction with the NARUC meeting scheduled to be held there), and inviting agenda topics (all interested

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

[92] Topics that the Task Force may consider include: (i) identifying barriers that inhibit planning and development of optimal transmission necessary to achieve federal and state policy goals, as well as potential solutions to those barriers; (ii) exploring potential bases for one or more states to use FERC-jurisdictional transmission planning processes to advance their policy goals, including multi-state goals; (iii) exploring opportunities for states to voluntarily coordinate in order to identify, plan, and develop regional transmission solutions; (iv) reviewing FERC rules and regulations regarding planning and cost allocation of transmission projects and potentially identifying recommendations for reforms; (v) examining barriers to the efficient and expeditious interconnection of new resources through the FERC-jurisdictional interconnection processes, as well as potential solutions to those barriers; and (vi) discussing mechanisms to ensure that transmission investment is cost effective, including approaches to enhance transparency and improve oversight of transmission investment including, potentially, through enhanced federal-state coordination.

persons, including all state commissions, were invited to file comments in this docket on agenda topics for the first public meeting on or before September 10, 2021).[93]

- **Climate Change, Extreme Weather, and Electric Sys. Reliability: Jun 1-2 Technical Conference (AD21-13)**

On June 1-2, 2021, FERC staff convened a technical conference to discuss issues surrounding the threat to electric system reliability posed by climate change and extreme weather events. This technical conference addressed (i) concerns that, because extreme weather events are increasing in frequency, intensity, geographic expanse, and duration, the number and severity of weather-induced events in the electric power industry may also increase; and (ii) specific challenges posed to electric system reliability by climate change and extreme weather, which may vary by region. The FERC seeks to understand the near, medium and long-term challenges facing the regions of the country; how decision makers in the regions are evaluating and addressing those challenges; and whether further FERC action is needed to help achieve an electric system that can withstand, respond to, and recover from extreme weather events. Pre-technical conference comments were due on or before April 15, 2021 and were filed by, among others, ISO-NE, AEE, Dominion, EDF, Eversource, Exelon, LS Power, National Grid, PSEG, Vistra, APPA, Capital Power, EEI, NARUC, NEI, NERC, NRECA, and the R Street Institute. Speaker materials were posted in eLibrary on June 3, 2021; transcripts of the June 1-2 days, July 22, 2021.

On August 11, 2021, the FERC issued a notice inviting post-technical conference comments. Comments can address the questions raised in the notice, as well as any other issues raised during the technical conference or identified in the Supplemental Notices of Technical Conference issued March 15 and May 21, 2021. Comments must be submitted on or before September 27, 2021.

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

On April 29, 2021, the FERC convened a Commissioner-led technical conference to discuss electrification—the shift from non-electric to electric sources of energy at the point of final consumption (e.g., to fuel vehicles, heat and cool homes and businesses, and provide process heat at industrial facilities). The purpose of the technical conference was to "initiate a dialog between Commissioners and stakeholders on how to prepare for an increasingly electrified future." Panel discussions addressed (1) projections, drivers, and risks of electrification; (2) infrastructure requirements of electrification (the extent to which electrification may influence or necessitate additional transmission and generation infrastructure); (3) transmission and distribution system services provided by flexible demand (how newly electrified sources of energy demand (e.g., electric vehicles, smart thermostats, etc.) could provide grid services and enhance reliability); and (4) the role of local, state, and federal coordination as electrification advances. On May 17, the FERC issued a notice inviting the submission of post-technical conference comments, on or before July 1, 20201, addressing issues raised during the technical conference and/or identified in the April 14, 2021 Supplemental Notice of Technical Conference. Nearly 20 sets of comments were filed, including comments by: AGA, CAISO, EEI, IL ICC, MISO, MISO TOs, Organization of MISO States, NEMA, NRECA, Chargepoint, CTC Global, Electrify America, Entergy, Environmental Defense Fund, ITC Holdings, Prairie Power, and National Grid. Since the last Report, R Street Institute submitted late-filed comments. This matter remains pending before the FERC.

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

March 23 Tech Conf (PJM). The FERC convened a Commissioner-led technical conference was on March 23, 2021 to provide input to the Commission on resource adequacy in the evolving electricity sector. Speaker materials from the March 23 technical conference have been posted to eLibrary. On March 29, Ohio PUC Commission Dan Conway submitted written comments. On April 5, the FERC issued a notice inviting post-technical conference comments on specific PJM-specific questions. Initial comments were due on or before April 26, 2021; reply comments must be submitted on or before May 10, 2021. More than 45 sets of comments were

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

filed, including by: AEE, Calpine, Cogentrix, Dominion, Exelon, FirstLight, LS Power, NESCOE, NEPGA, NRG, PSEG, Shell, Vistra, CT DEEP, EEI, EPSA, and NRECA/APPA, some of which addressed issues to be discussed in the May 25 New England technical conference (identified immediately below). On May 10, 2021, reply comments were filed by the American Clean Power Association ("ACPA"), AEP, EPSA, Exelon, Joint Consumer Advocates, LS Power, Old Dominion Electric Cooperative ("ODEC"), PJM Power Providers ("P3"), Public Interest Organizations ("PIOs"), and the Retail Electric Supply Association ("RESA").

May 25 Tech Conf (New England). On May 25, 2021, the FERC held a Commissioner-led technical conference regarding the wholesale markets administered by ISO New England Inc. Supplemental notices of the technical conference were issued on May 3 and May 17. The May 17 supplemental notice identified panelists and topics/questions for discussion for the technical conference. Panel discussions included: (1) a Commissioner-led discussion of the relationship between state policies and the New England Markets; (2) a Staff-led discussion of short-term options and complementary potential market changes to accommodate state policies in New England; and (3) a Staff-led discussion of long-term options and centralized procurement of clean energy.

Post (New England) Tech Conf Comments. On June 4, 2021, the FERC issued a notice inviting post-technical conference comments on the issues raised during the technical conference, including the questions listed in the May 17, 2021 supplemental notice. Post-technical conference comments were due on or before ***July 19, 2021*** and were filed by: AEE, Calpine, CT Parties, Dominion, Eversource, MMWEC, NESCOE, NEPGA, NextEra, NRG, Public Interest Orgs, Vistra, AEMA, EPSA, RENEW.

- **Modernizing Electricity Market Design - Energy and Ancillary Service Markets (AD21-10)**

On July 19, 2021, the FERC issued a notice that it will convene two staff-led technical conferences by WebEx addressing ISO/RTO energy and ancillary services markets. The technical conferences will discuss potential energy and ancillary services market reforms, such as market reforms to increase operational flexibility, that may be needed as the resource fleet and load profiles change over time. The first technical conference will be held on Tuesday, September 14, 2021; the second, Tuesday, October 12, 2021. Each conference is scheduled to run from 9-5 p.m.

Tech Conf I (Sep 14). The FERC will convene remotely on September 14, 2021 a full-day technical conference to discuss potential energy and ancillary services market reforms, such as market reforms to increase operational flexibility, that may be needed as the resource fleet and load profiles change over time. Specifically, in a supplemental notice issued on August 17, 2021, the FERC identified the following four panels and the topics and questions to be discussed: (1) Understanding the Need for Additional Operational Flexibility in RTO/ISO Energy and Ancillary Services Markets; (2) Revising Existing Operating Reserve Demand Curves ("ORDCs") to Address Operational Flexibility Needs in RTOs/ISOs; (3) Creating New Products to Address Operational Flexibility Needs in RTOs/ISOs; and (4) Market Design Issues and Tradeoffs to Consider in Reforms to Increase Operational Flexibility in RTO/ISO Energy and Ancillary Services Markets. Speakers have not been identified. Information on this technical conference, including a link to the webcast, will be posted on the conference's event page on the FERC's website (https://www.ferc.gov/news-events/events/technical-conference-regarding-energy-and-ancillary-services-markets-09142021) prior to the event.

Tech Conf II (Oct 12). The FERC will also convene remotely on October 12, 2021 a second full-day technical conference to discuss potential energy and ancillary services market reforms. Information on this technical conference will be issued following the September 14 technical conference.

- **Office of Public Participation (AD21-9)**

On June 24, 2021, the FERC issued a report in which it detailed the forthcoming creation of the Office of Public Participation ("OPP"), which it intends to grow over the course of a four-year period before OPP reaches its full operating status by the close of Fiscal Year ("FY") 2024. By the end of FY2021, the FERC plans to hire the OPP Director, as well as the Deputy Director and an administrative staff member. The FERC plans to assess OPP's workload and reevaluate needed resources for additional growth into and beyond FY2024 to ensure meaningful and consistent compliance with FPA section 319. A report, prepared by M.J. Bradley & Associates for NRDC's Sustainable FERC Project, summarizing stakeholder feedback provided to the FERC through listening sessions and written comments, was posted to the FERC's eLibrary on August 3, 2021.

Since the last Report, on August 23, 2021, the FERC issued a notice of a virtual workshop to be held on September 16, 2021, from 1:00 p.m. to 4:30 p.m., to discuss technical assistance in electric proceedings, solicit public input on their technical assistance needs, and explore ways OPP could work with external entities to facilitate technical assistance to interested parties. Further details on the agenda, including registration information, can be found on the U.S. Department of Energy's ("DOE") Pacific Northwest National Laboratory ("PNNL") website. Information on this technical workshop will also be posted on the Calendar of Events on the FERC's website, www.ferc.gov, prior to the workshop.

- **ISO/RTO Credit Principles and Practices (AD21-6)**

On February 25-26, 2021, the FERC held a technical conference to discuss principles and best practices for credit risk management in ISO/RTOs. Panel topics included: Credit Principles and Practices in ISOI/RTO Markets; RTO/ISO Comparison of Risk Management Structure, Credit Enhancements and Lessons Learned; Internal Resources and Expertise within RTOs/ISOs; Impact of Market Design on Credit Risk; Addressing Counterparty Risk: Minimum Participation Requirements and Know Your Customer Protocols; and Collateral, Initial and Variation Margining for FTR and non-FTR positions. Speaker materials and a transcript of the technical conference are posted in the FERC's eLibrary.

On April 21, 2021, the FERC issued a notice inviting post-technical conference comments on the issues raised during the technical conference, including the questions listed in the February 24, 2021 supplemental notice of the technical conference and in the attachment to the April 21 notice. Post-technical conference comments were due on or before June 7, 2021 and were filed by ISO-NE, Appian Way, Committee of Chief Risk Officers, CPV, DC Energy, Energy Trading Institute, EPSA, Financial Marketers Coalition, ISO/RTO Council, MISO, NYISO, PJM, SPP, and Vitol. On July 6, NEPOOL filed comments in response to the IRC comments that, to the extent Tariff changes are to be proposed, the Tariff changes be vetted first pursuant to the Participant Processes set forth in the Participants Agreement. This matter is pending before the FERC.

- **Offshore Wind Integration in RTOs/ISOs Tech Conf (Oct 27, 2020) (AD20-18)**

On October 27, 2020, the FERC convened a staff-led technical conference to consider whether and how existing RTO and ISO interconnection, merchant transmission and transmission planning frameworks can accommodate anticipated growth in offshore wind generation in an efficient or cost-effective manner that safeguards open access transmission principles. The conference also provided an opportunity for participants to discuss possible changes or improvements to the current regulatory frameworks that may accommodate such growth. Speaker materials and a transcript of the technical conference are posted in eLibrary. Since the last Report, Advanced Power Alliance filed comments requesting that the FERC issue a notice providing an opportunity for interested persons to submit post-conference comments and to thereafter "take action to facilitate transmission planning and interconnection policies that will enable construction of the cost-effective, efficient, resilient and environmentally-sound transmission infrastructure needed to connect new offshore wind generation to the onshore grid."

On March 11, 2021, the FERC issued a notice inviting interested persons to file, on or before May 10, 2021, post-technical conference comments on the questions listed in the attachment to its Notice or to the questions outlined in the October 22, 2020 supplemental notice of technical conference. Post-technical conference comments were filed by over 30 parties, including: ISO-NE, NESCOE, Anbaric, ConEd, Eversource, National Grid, NRDC et al., Orsted, Shell, CT DEEP, EEI, MA DOER, RENEW et al., and RWE Renewables Americas. This matter is pending before the FERC.

- **Hybrid Resources (AD20-9)**

As previously reported, the FERC convened a July 23, 2020 technical conference to discuss technical and market issues prompted by growing interest in projects that are comprised of more than one resource type at the same plant location ("hybrid resources"). The focus was on generation resources and electric storage resources paired together as hybrid resources. Speaker materials and a transcript of the technical conference have been posted to the FERC's eLibrary. Post-technical conference comments were filed by ISO-NE, CAISO, MISO, NYISO, PJM, Enel, American Council on Renewable Energy, AWEA, EEI, EPRI, R Street Institute, Savion, and SEIA.

On January 19, 2021, the FERC issued an order directing each ISO/RTO to submit, within 6 months (or before July 19, 2021), a report that provides: (a) a description of its current practices related to each of the following four hybrid resource issues: (1) terminology; (2) interconnection; (3) market participation; and (4) capacity valuation (collectively, the "Issues"); (b) an update on the status of any ongoing efforts to develop reforms related to each of the Issues; and (c) responses to the specific requests for information contained in the order. The ISO/RTO Reports, including ISO-NE's, were filed on July 19, 2021. Public comments in response to the ISO/RTO reports are now due September 20, 2021.[94] Thus far, comments have been submitted by the City of New York.

Hybrid Resources White Paper. On May 26, 2021, the FERC issued a white paper that discusses the hybrid resources technical conference, as well as information learned in post-technical conference comments. Interested persons were invited to submit comments on the white paper and encouraged to jointly respond to both the white paper and RTO/ISO informational reports where applicable to avoid duplicate comments. Comments on the white paper will also be due on September 20, 2021.

- **ANOPR: Transmission Planning and Allocation and Generator Interconnection (RM21-17)**

On July 15, 2021, the FERC issued an advanced notice of proposed rulemaking ("ANOPR")[95] to consider whether there should be changes in the regional transmission planning and cost allocation and generator interconnection processes and, if so, which changes are necessary to ensure that transmission rates remain just and reasonable and not unduly discriminatory or preferential and that reliability is maintained. Specifically, the ANOPR discusses proposals or concepts for changes to existing processes in several broad categories: regional transmission planning, regional cost allocation, generator interconnection funding, generator interconnection queueing processes and consumer protection, and in several instances the ANOPR also offers a potential rationale or argument for potential proposals. The FERC seeks comments from the public on these proposals and welcomes commenters to offer additional or alternative proposals for consideration. Comments on the *Transmission Planning & Allocation/Generation Interconnection ANOPR* are currently due October 12, 2021; reply comments, November 9, 2021.[96] Requests for an extension of time to submit comments have been filed by the ISO/RTO Council ("IRC"), Organization of MISO States ("OMS"), and Organization of PJM States ("OPSI"). Those requests, which request that comment date be extended to December 1, 2021 (an additional 50 days), and reply comments be extended to January 31, 2022 (an additional 30 days to the reply comment period), are pending before the FERC. In addition, eight individuals have thus far filed form comments. The ANOPR, including any potential NEPOOL comments, is being considered by the Transmission Committee.

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[94] Public comments were initially due August 18, 2021. However, in response to a request by the Energy Storage Association ("ESA"), the American Clean Power Association ("ACP"), and Solar Energy Industry Association ("SEIA"), the FERC granted a 30-day extension of time, to September 20, 2021, to file comments in response to the ISO/RTO reports.

[95] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 176 FERC ¶ 61,024 (July 15, 2021) ("*Transmission Planning & Allocation/Generation Interconnection ANOPR*").

[96] The *Transmission Planning & Allocation/Generation Interconnection ANOPR* was published in the *Fed. Reg.* on July 27, 2021 (Vol. 86, No. 141) pp. 40,266-40,298.

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

On March 18, 2021, the FERC issued a NOI[97] seeking comments on whether to revise its Demand Response ("DR") Opt-Out regulations established in *Orders 719 and 719-A.* Those regulations require an ISO/RTO not to accept bids from an aggregator of retail customers ("ARC") that aggregates DR of the customers of utilities that distributed more than 4 million MWh in the previous fiscal year, where the relevant electric retail regulatory authority prohibits such customers' DR to be bid into ISO/RTO markets by an ARC. The FERC now seek information to help it examine the potential costs/burdens and benefits, both quantitative and qualitative, of removing the DR Opt-Out, as well as other changes relating to DR since the FERC issued *Orders 719 and 719-A*. The FERC is not seeking comment on the Small Utility Opt-In. Comments on the NOI, following an extension, were due on or before July 23, 2021 and were filed by nearly 30 parties, including by AEE, Voltus, AEMA, APPA/NRECA, EEI, and NARUC. Reply comments were due on or before August 23, 2021, and were filed by AEP, Armada Power, Entergy, Southern Pioneer Electric, Voltus, State Commissions from LA/MS, MI, MO, NC, APPA/NRECA, Assoc. of Bus. Advocating Tariff Equity ("ABATE"), and PIOs.

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

On December 17, 2020, the FERC issued a NOPR[98] proposing to establish rules for incentive-based rate treatment for voluntary cybersecurity investments by a public utility for or in connection with the transmission or sale of electric energy subject to FERC jurisdiction, and rates or practices affecting or pertaining to such rates for the purpose of ensuring the reliability of the BPS.

Comments on the *Cyber security Incentives NOPR* were due on or before April 6, 2021. Comments were filed by: NECPUC, APPA, EEI, EPSA, LPPC, NERC, NRECA, TAPS, Accenture, aDolus Inc. et al.,[99] Alliant, Anterix, Bureau of Reclamation, CA Dept of Water Resources State Water Project/CPUC, George Cotter, FRS, Hitachi ABB Power Grids, IECA, ITC, Joint Consumer Advocates, MI PUC, Org of MISO States, MISO TOs, PJM TOs, and Public Citizen. Reply comments were due May 6, 2021[100] and were filed by APPA/TAPS, EEI, SEIA, California Public Utilities Commission and California Department of Water Resources ("CA PUC/DWR"), and the Office of the Ohio Federal Energy Advocate ("Ohio FEA"). This matter remains pending before the FERC.

- **NOPR: Managing Transmission Line Ratings (RM20-16)**

On November 19, 2020, the FERC issued a NOPR[101] proposing to reform both the *pro forma* OATT and its regulations to improve the accuracy and transparency of transmission line ratings. Specifically, the NOPR proposes to require: transmission providers to implement ambient-adjusted ratings on the transmission lines over which they provide transmission service; ISO/RTOSs to establish and implement the systems and procedures necessary to allow transmission owners to electronically update transmission line ratings at least hourly; and transmission owners to share transmission line ratings and transmission line rating methodologies with their respective transmission provider(s) and, in ISO/RTOs, with their respective market monitor(s). Comments on the *Managing Transmission Line Ratings NOPR* were due on or before March 22, 2021.[102] Comments were submitted by over 50 parties, including by ISO-NE, DC Energy, Dominion, EDF, ENEL/EnerNOC, Eversource, Exelon, NRDC,

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[97] *Participation of Aggregators of Retail Demand Response Customers in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 174 FERC ¶ 61,198 (March 18, 2021) ("*DR Aggregator NOI*").

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

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

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

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

[102] The *Managing Transmission Line Ratings NOPR* was published in the *Fed. Reg.* on Jan. 21, 2021 (Vol. 86, No. 12) pp. 6,420-6,444.

Vistra, EEI, EPRI, EPSA, New England State Agencies,[103] NRECA/LPPC, and Potomac Economics. Reply comments were submitted by the Enel Companies, EPSA, PJM, OMS, Potomac Economics, NRECA/LPCC, and ITC Holdings Corp and the Utah Division of Public Utilities. This matter is pending before the FERC.

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

Supplemental NOPR. In light of comments already received in this proceeding,[104] the FERC issued on April 15, 2021 a *Supplemental NOPR*[105] to propose and seek comment on a revised incentive for transmitting and electric utilities that join Transmission Organizations ("Transmission Organization Incentive"). The Incentive would be reduced from 100 to 50 basis points and would be available only for three years. The FERC seeks comment on whether voluntary participation should be a requirement, and if so, how "voluntary" should be determined. In addition, the FERC now proposes to require each utility that has received a Transmission Organization Incentive for three or more years to submit a compliance filing revising its tariff to remove the incentive from its transmission tariff. The *Supplemental NOPR* did not address the other proposals contained in the *March NOPR*.[106] A more detailed summary of the NOPR was distributed to the Transmission Committee and discussed at the TC's March 25, 2020 meeting.

Comments on the *Supplemental NOPR* were due on or before June 25, 2021. Over 60 sets of comments were filed, including by the New England TOs, MMWEC/NHEC/CMMEC, NECOS, NESCOE, Potomac Economics, and CT PURA. Reply comments were due on or before July 26, 2021, with 28 sets of comments received, including by the New England TOs, NECOS, NESCOE, CT PURA/CT DEEP/MA AG, CT AG, and Public Interest Groups.[107] Since the

[103] "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.

[104] Over 80 sets of comments on the *March NOPR* were filed on or before the July 1, 2020 comment date, including comments by: Avangrid, EDF Renewables, EMCOS, Eversource, Exelon, LS Power, MMWEC/NHEC/CMEEC, National Grid, NESOCE, NextEra, UCS, CT PURA, and Potomac Economics. Reply comments were filed by AEP, ITC Holding, the N. California Transmission Agency, and WIRES.

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

[106] As previously reported, the *March NOPR* proposed revisions to the FERCs existing transmission incentives policy and corresponding regulations, including the following:

- A shift from risks and challenges to a ***consumers'' benefits test*** that focuses on ensuring reliability and reducing the cost of delivered power by reducing transmission congestion.
- ***ROEs incentive for Economic Benefits***. A 50-basis-point adder for transmission projects that meet an economic benefit-to-cost ratio in the top 75th percentile of transmission projects examined over a sample period and an additional 50-basis-point adder for transmission projects that demonstrate *ex post* cost savings that fall in the 90th percentile of transmission projects studied over the same sample period, as measured at the end of construction.
- ***ROE for Reliability Benefits***. A 50-basis-point adder for transmission projects that can demonstrate potential reliability benefits by providing quantitative analysis, where possible, as well as qualitative analysis.
- ***Abandoned Plant Incentive***. 100 percent of prudently incurred costs of transmission facilities selected in a regional transmission planning process that are cancelled or abandoned due to factors that are beyond the control of the applicant. Recovery from the date that the project is selected in the regional transmission planning process.
- ***Eliminate Transco Incentives***.
- ***Transmission Organization Incentive.*** A *50-basis-point increase* for transmitting utilities that turn over their wholesale facilities to a Transmission Organization and *only for the first three years after transferring operational control of its facilities.* The FERC seeks comment as to whether participation must be voluntary to receive the incentive, and if so, how the CFERC should determine whether the decision to join is voluntary.
- ***Transmission Technologies Incentives***. Eligible for both a stand-alone, 100-basis-point ROE incentive on the costs of the specified transmission technology project and specialized regulatory asset treatment. Pilot programs presumptively eligible (though rebuttable).
- ***250-Basis-Point Cap***. Total ROE incentives capped at 250 basis points in place of current "zone of reasonableness" limit.
- ***Updated Date Reporting Processes***. Information to be obtained on a project-by-project basis, information collection expanded, updated reporting process.

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

last Report, reply comments were posted from New England State Parties,[108] Alliant/Consumers/DTE, AEP, Pacific Gas & Electric, Joint Consumer Advocates, and the American Clean Power Association.

September 10, 2021 Workshop. The FERC will convene a workshop on September 10, 2021[109] to discuss certain performance-based ratemaking approaches, particularly shared savings, that may foster deployment of transmission technologies. The notice states that the workshop will explore: the maturity of the modeling approaches for various transmission technologies; the data needed to study the benefits/costs of such technologies; issues pertaining to access to or confidentiality of this data; the time horizons that should be considered for such studies; and other issues related to verifying forecasted benefits. The workshop may also discuss whether and how to account for circumstances in which benefits do not materialize as anticipated and may explore other performance-based ratemaking approaches for transmission technologies seeking incentives under FPA section 219, particularly market-based incentives. Since the last Report, on August 23, 2021, the FERC issued an agenda for the workshop, which includes the final workshop program and expected speakers.

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

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

Order 2222. On September 17, 2020, the FERC issued a final rule ("*Order 2222*")[110] adopting reforms to remove what it found were barriers to the participation of distributed energy resource ("DER")[111] 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;

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108 "New England State Parties" are CT PURA, CT DEEP and the MA AG.

109 Notice of Workshop, *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*, Docket Nos. RM20-10 and AD19-19 (Apr. 15, 2021).

110 *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 2222, 172 FERC ¶ 61,247 (Sep. 17, 2020) ("*Order 2222*").

111 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."

(9) address modifications to the list of resources in a DER aggregation;

(10) address market participation agreements for DER aggregators; and

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

ISO-NE Compliance. On May 24, 2021, the FERC approved the extension of time requested by ISO-NE, to February 2, 2022 (2/2/222), to comply with *Order 2222*.[112] In granting the extension of time, as it did for MISO, SPP and PJM, the FERC directed ISO-NE to submit an informational filing indicating any changes to the stakeholder process schedule provided in its extension request on or before June 23, 2021 and to submit status reports every 90 days thereafter until the date that ISO-NE submits its compliance filing.[113] ISO-NE submitted its first report on June 22, 2021. In that report, ISO-NE stated that the "stakeholder schedule included in ISO-NE's motion for an extension of time has not been modified. Various NEPOOL stakeholders provided feedback on the ISO-NE's draft compliance proposal in June. The ISO plans to respond to that feedback before presenting its final draft compliance design and initial Tariff redlines in September, leading, ultimately, to the filing of a compliance proposal on February 2, 2022." Materials associated with ISO-NE's *Order 2222* compliance process can be viewed on the ISO-NE website's Order 2222 Key Project page.

Order 2222-A. On March 18, 2021, the FERC issued *Order 2222-A*,[114] which addressed arguments on rehearing and set aside and clarified *Order 2222* in part. Specifically, as is its right under *Allegheny*, the FERC modified the discussion in *Order 2222* and set aside *Order 2222*, in part, by finding that the participation of demand response in DER aggregations is subject to the opt-out and opt-in requirements of *Orders 719* and *719-A,* providing further clarification on the FERC's interconnection policies pertaining to Qualifying Facilities ("QFs"), and modifying § 35.28(g)(12)(i) to make a non-substantive ministerial correction. Requests for rehearing and/or clarification of *Order 2222-A* were due on or before April 19, 2021 and were filed by: AEE/AEMA (Advanced Energy Management Alliance), EEI, National Association of Regulatory Utility Commissioners ("NARUC"), Louisiana Public Service Commission ("LPSC") and the Mississippi Public Service Commission ("MPSC"), North Carolina Utilities Commission, the MISO Transmission Owners ("MISO TOs"), and Voltus. On April 30, MISO filed comments supporting the rehearing requests filed by NARUC, LPSC/MPSC and the MISO TOs. On May 4, ISO-NE answered the AEE/AEMA request for clarification and/or rehearing of *Order 2222*. On May 14, AEE/AEMA answered ISO-NE's May 4 answer.

On May 20, 2021, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration". The Notice confirmed that the 60-day period during which a petition for review of *Order 2222-A* can be filed with an appropriate federal court was triggered when the FERC did not act on the requests for rehearing of *Order 2222-A*.[115] The Notice also indicated that the FERC would address, as is its right, the rehearing

[112] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Indep. Sys. Operators*, 175 FERC ¶ 61,156 (May 24, 2021) ("*ISO-NE Order 2222 Compliance Extension*").

[113] *Id.* at P 5.

[114] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Indep. Sys. Operators*, Order No. 2222-A, 174 FERC ¶ 61,197 (Mar. 18, 2021) ("*Order 2222-A*").

[115] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Indep. Sys. Operators*, 175 FERC ¶ 62,109 (May 20, 2021) ("*Notice of Denial of Rehearings By Operation of Law*").

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."[116]

Order 2222-B. On June 17, 2021, the FERC issued *Order 2222-B*,[117] which as permitted by FPA section 313(a), modified the discussion in *Order 2222-A* and set aside, in part, and clarified, in part, that decision. Specifically, *Order 2222-B* set aside the decision in *Order 2222-A* to decline to extend the opt-out and opt-in requirements of Order Nos. 719 and 719-A to demand response resources participating in heterogeneous distributed energy resource aggregations (finding that these issues are better addressed in Docket No. RM21-14). *Order 2222-B* also provides further clarification regarding appropriate restrictions to avoid double counting of services and the compensation of demand response resources that participate in heterogeneous distributed energy resource aggregations. *Order 2222-B* will become effective August 27, 2021.[118]

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

As previously reported, *Order 860,*[119] issued three years after the FERC's *Data Collection NOPR,*[120] (i) revises the FERC's MBR regulations by establishing a relational database of ownership and affiliate information for MBR Sellers (which, among other uses, will be used to create asset appendices and indicative screens), (ii) reduces the scope of information that must be provided in MBR filings, modifies the information required in, and format of, a MBR Seller's asset appendix, (iii) changes the process and timing of the requirements to advise the FERC of changes in status and affiliate information, and (iv) eliminates the requirement adopted in *Order 816* that MBR Sellers submit corporate organization charts. In addition, the FERC stated that it will not adopt the *Data Collection NOPR* proposal to collect Connected Entity data from MBR Sellers and entities trading virtuals or holding FTRs. The FERC has posted on its website high-level instructions that describe the mechanics of the relational database submission process and how to prepare filings that incorporate information that is submitted to the relational database. As recently extended (*see* below), *Order 860* became effective July 1, 2021, and submitters have until close of business on November 2, 2021 to make their initial baseline submissions. Submitters will be required to obtain FERC-generated IDs for reportable entities that do not have CIDs or LEIs, as well as Asset IDs for reportable generation assets without an EIA code so that every ultimate upstream affiliate or other reportable entity has a FERC-assigned company identifiers ("CID"), Legal Entity Identifier,[121] 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,[122] 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."

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[116] *Id.*

[117] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Indep. Sys. Operators*, Order No. 2222-B, 175 FERC ¶ 61,227 (June 17, 2021) ("*Order 2222-B*").

[118] *Order 2222-B* was published *Fed. Reg.* on June 28, 2021 (Vol. 86, No. 121) pp. 33,853-33,861.

[119] *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).

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

[121] 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.

[122] *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*").

MBR Database. On January 10, 2020, the FERC issued a notice that updated versions of the XML, XSD, and MBR Data Dictionary are available on the FERC's website and that the test environment for the MBR Database is now available and can be accessed on the MBR Database webpage.

March 18 Notice. On March 18, 2021, the FERC issued a notice seeking comments on proposed changes to the MBR Data Dictionary to reflect the affiliations, or lack of affiliation, among Sellers for which their ultimate upstream affiliate is an institutional investor who acquired their securities pursuant to a section 203(a)(2) blanket authorization.[123] Specifically, the FERC proposes to update the MBR Data Dictionary and add the following three new attributes to the Entities table: the blanket authorization docket number, and the utility ID types and the utility IDs of the utilities whose securities were purchased under the corresponding blanket authorization docket number. Appropriate Sellers would be required to submit the docket number of the proceeding in which the FERC granted the section 203(a)(2) blanket authorization and the upstream affiliate whose securities were acquired pursuant to the section 203(a)(2) blanket authorization. Comments on the Notice were due on or before June 7, 2021,[124] and were filed by EEI, the Global LEI Foundation, TAPS, and XBRL US. In light of the proposed changes, the FERC deferred by three months the effective date of *Order 860* and its associated deadlines.

Effective Date: July 1, 2021; Baseline Submissions November 2, 2021; First change in Status Filings, November 30, 2021. On March 18, 2021, the FERC issued a notice extending the effective and associated implementation dates of *Order 860* by an additional *three* months. The new *Order 860* effective date was July 1, 2021, and the deadline for baseline submissions will be to and including November 2, 2021. First change in status filings under these new timelines will be due November 30, 2021.

Order Adopting Changes to MBR Database. On August 19, 2021, the FERC issued an order revising the MBR Data Dictionary as proposed in the March 18 Notice.[125] Specifically, Sellers whose ultimate upstream affiliate(s) own their voting securities pursuant to a section 203(a)(2) blanket authorization must provide, in the MBR Database, three additional data fields: (1) the docket number of the section 203(a)(2) blanket authorization, (2) the Utility_ID_Type_CD of the utility whose securities were acquired under the corresponding section 203(a)(2) blanket authorization docket number, and (3) the Utility ID of that utility.

- ***Order 676-J*: Incorporation of NAESB WEQ Standards v. 003.3 into FERC Regs (RM05-5-029, -030)**

On May 20, 2021, the FERC issued Order 676-J,[126] which revises FERC regulations to incorporate by reference the latest version (Version 003.3) of the Standards for Business Practices and Communication Protocols for Public Utilities adopted by the Wholesale Electric Quadrant ("WEQ") of the North American Energy Standards Board ("NAESB"). The WEQ Version 003.3 Standards include, in their entirety, the WEQ-023 Modeling Business Practice Standards contained in the WEQ Version 003.1 Standards, which address the technical issues affecting Available Transfer Capability ("ATC") and Available Flowgate Capability ("AFC") calculation for wholesale electric transmission services, with the addition of certain revisions and corrections. The FERC also revised its regulations to provide that transmission providers must avoid unduly discriminatory and preferential treatment in the calculation of ATC. *Order 676-J* became effective August 2, 2021.[127] Public utilities must make a compliance filing to comply with the requirements of this final rule through eTariff 12

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

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

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

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

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

months after implementation of the WEQ Version 003.2 Standards. Compliance filings for cybersecurity and Parallel Flow Visualization standards are due March 2, 2022.

- **Waiver of Tariff Requirements (PL20-7)**

On May 21, 2020, the FERC issued a Proposed Policy Statement that would clarify its policy regarding requests for waiver of tariff provisions.[128] The *Proposed Policy Statement* sets forth the approach the FERC would take going forward to ensure compliance with the filed rate doctrine and the rule against retroactive making. The proposed policy will both clarify and modify waiver standards, and in some instances, make it harder to obtain waivers.

Specifically, the FERC proposed the following guidance on filing procedures to implement its new approach for granting waivers of tariff provisions and to no longer grant retroactive waivers except as consistent with the *Proposed Policy Statement*:

1. *Style Requests as Requests for Remedial Relief*. Filings seeking relief in connection with actions or omissions that have already occurred prior to the date relief is sought from the FERC would be characterized as a request for remedial relief (rather than as a request for a waiver). In response to such a request, the FERC will focus on what remedy, if any, is required to cure acknowledged or alleged deviations from a filed tariff. "Waiver" is to be limited to (a) requests for prospective relief when a requested future deviation from the filed tariff has not yet occurred at the time a request is filed; or (b) petitions for remedial relief when a tariff expressly authorizes regulated entities to seek a remedial waiver from the FERC for past non-compliance with the filed tariff.

2. *Form of Filing*. When the entity requesting remedial relief is the entity that acted (or believes it may have acted) in a manner inconsistent with the tariff, such requests should be filed as petitions for declaratory order under Rule 207 of the FERC's Rules of Practice and Procedure. When the filing entity alleges a different entity has acted in a manner inconsistent with the tariff, such requests should be filed as complaints under Rule 206. Given the filing fees associated with petitions for declaratory order, the industry was encouraged to directly address this aspect of the proposal.

3. *Expressly Request FERC Action pursuant to FPA section 309 or NGA section 16.4*. These provisions have been found to afford the FERC the latitude to remedy past non-compliance "provided the agency's action conforms with the purposes and policies of Congress and does not contravene any terms of the Act."

The FERC acknowledged that this Policy would represent a change from its past approach, particularly in situations where inadvertent failures to comply with ministerial tariff requirements have not been protested. The FERC suggested a few ways tariffs may be modified to avoid what may appear by comparison to be harsh outcomes, including expressly stating in the tariff that a failure to comply with a certain deadline may be waived by order of the FERC or by allowing various kinds of errors to be cured within a reasonable period of time after a default has occurred or an error has been discovered, but is difficult to imagine how feasible or how well these options might work in practice.

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

The FERC proposed to incorporate its current four-part analysis[129] 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,[130] 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,[131] INGAA, Kansas Electric Power Coop. ("KEPC"), NGA, NGSA, NRECA, Public Citizen, Sunflower Electric Power, and TAPS. Reply comments were filed by APPA, Joint Trade Associations,[132] KEPC, and the Sustainable FERC Project. The proposed Policy Statement remains pending before the FERC.

- **FERC's ROE Policy for Natural Gas and Oil Pipelines (PL19-4)**

On May 21, 2020, the FERC issued a Policy Statement that applies to natural gas and oil pipelines, with certain exceptions to account for the statutory, operational, organizational and competitive differences among the electric, natural gas and oil pipeline industries, the FERC's ROE methodology adopted in *Opinion No. 569-A*.[133] 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").[134] 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

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[129] 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.

[130] *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.

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

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

[133] *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*").

[134] 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.[134] 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).

policy. This Policy Statement became effective May 27, 2020.[135] 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[136] answered the New England TO's May 10 supplemental comments. On June 15, 2020, Joint Parties[137] 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.[138] WIRES submitted supplemental comments on June 18, 2020 requesting that the FERC take further action in this proceeding to "resolve the uncertainty surrounding its base ROE methodology and establish a policy consistent with the recommendations made in these comments" (recommending a framework that employs all four of the previously proposed ROE models, including the Expected Earnings model, along with certain modifications, to ensure that ROEs attract capital investment in needed transmission infrastructure). On June 24, EEI and WIRES requested the FERC issue a NOI regarding the FERC's policy for determining base ROE applicable to the electric industry as a whole. Six Cities answered Joint Parties on June 30. APPA answered EEI and WIRES' June 24 motion.

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

As previously reported, the FERC's February 18, 2021 notice of inquiry ("*2021 NOI*") sought new information and additional stakeholder perspectives to help the FERC explore whether it should revise its approach under the currently effective policy statement on the certification of new natural gas transportation facilities to determine whether a proposed natural gas project is or will be required by the public convenience and necessity, as that standard is established in NGA section 7.[139] 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.[140] Comments on the *2021 NOI* were due May 26, 2021. In all, more than 130 sets of comments were filed, including a large number from concerned private citizens. This matter is pending before the FERC.

XIII. FERC Enforcement Proceedings

Electric-Related Enforcement Actions

- ***Terra-Gen (IN21-7)***

On August 2, 2021, the FERC approved a Stipulation and Consent Agreement with Terra-Gen, LLC[141] ("Terra-Gen") that resolved OE's investigation into whether Terra-Gen submitted false or misleading information to the California Independent System Operator ("CAISO") about the physical capabilities of

[135] 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.

[136] 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.

[137] "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.

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

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

[140] *Id.* at P 3.

[141] *Terra-Gen, LLC*, 176 FERC ¶ 61,071 (Aug. 2, 2021).

Cameron Ridge[142] and whether Terra Gen violated the CAISO Tariff by deviating its wind farm's output from CAISO's dispatch instructions. Under the Settlement, in which Terra-Gen neither admits nor denies the alleged violations, Terra-Gen must ***disgorge $117,231*** plus interest,[143] and ***pay a $510,962 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).

- **PacifiCorp (IN21-6)**

On April 15, 2021, in the FERC's first-ever Show Cause Order addressing alleged violations of NERC Reliability Standards,[144] the FERC directed PacifiCorp to show cause why it should not be found to have violated FPA section 215(b)(1) and section 39.2 of the FERC's regulations by failing to comply with Reliability Standard FAC 009-1 (Establish and Communicate Facility Ratings), Requirement R1, and the successor Reliability Standard FAC-008-3 (Facility Ratings), Requirement R6 (collectively, "FAC-009-1 R1"), which requires a transmission owner to establish and have facility ratings that are consistent with its Facility Ratings Methodology ("FRM"). An Enforcement investigation found that clearance measurements on a majority of PacifiCorp's transmission lines were incorrect under the National Electric Safety Code, which were used to calculate PacifiCorp's facility ratings, thus making PacifiCorp's facility ratings inconsistent with its FRM. Enforcement alleges that PacifiCorp was aware of incorrect clearances on its system since at least 2007 when FAC-009-1 R1 became mandatory, but failed to identify and remedy them in a timely manner, and PacifiCorp's violations began on August 31, 2009, when it implemented its FRM policy, and at least some of the violations continued until August 2017 when PacifiCorp completed remediation of all of its incorrect clearances to make them consistent with its FRM. Enforcement also pointed to the role of the violations in the Wood Hollow, Utah wildfire that lasted from June 23 to July 1, 2012. In light of these alleged violations, the FERC directed PacifiCorp to show cause why it should not be assessed civil penalties in the amount of ***$42 million***.

On July 16, 2021, PacifiCorp answered the PacifiCorp Show Cause Order, denying the alleged violations of FAC-009. Enforcement's reply is due 60 days from the filing of PacifiCorp's answer, or September 14, 2021. Should the FERC choose to pursue a civil penalty against PacifiCorp for the alleged violations, PacifiCorp has already exercised its right to adjudicate these allegations in federal district court. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **GreenHat (IN18-9)**

On May 20, 2021, the FERC directed GreenHat Energy, LLC ("GreenHat"), John Bartholomew, Kevin Ziegenhorn, and [Luan Troxel as the Executor for] the Estate of Andrew Kittell ("Kittell Estate") (collectively, "Respondents") to show cause why they should not be found to have violated FPA section 222, along with section 1c.2 of the FERC's regulations, PJM Tariff Attachment Q, Section B and section 15.1.3 of PJM's Operating Agreement, by engaging in a manipulative scheme in PJM's Financial Transmission Rights ("FTR") market which generated more than $13 million in unjust profits for Respondents and imposed approximately $179 million in losses on PJM Members.[145] The FERC directed GreenHat, Bartholomew, Ziegenhorn, and the Kittell Estate to show cause why they should not be required, jointly and severally, to disgorge unjust profits of just ***over $13 million***, plus interest, and directed GreenHat, Bartholomew, and Ziegenhorn (but not the Kittell

[142] Cameron Ridge is a wind-powered electric generation facility owned by Terra-Gen's subsidiary Cameron Ridge, LLC. Terra-Gen represented that more than 50% of the resource was comprised of technology that was physically unable to curtail output, and could not be made to do so without significant investment. However, Terra-Gen formulated and implemented a practice to curtail Cameron Ridge's output in response to negative prices, as opposed to not being able to perform due to physical limitations, e.g., changes in wind speed, and therefore violated the CAISO Tariff each time it curtailed its resource in response to negative pricing.

[143] Shell's disgorgement is to be allocated to National Trading II ($13,391), Enstor Energy Services ($10,166), Macquarie Energy ($9,073), Noble Americas Gas & Power Corp. ($8,636), and ConocoPhillips Co. ($7,051).

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

[145] *GreenHat Energy, LLC et al.*, 175 FERC ¶ 61,138 (May 20, 2021) ("*GreenHat Show Cause Order*").

Estate) to show cause why they should not be assessed civil penalties of ***$179 million***, ***$25 million***, and ***$25 million***, respectively.

Respondents answered the *GreenHat Show Cause Order* on July 6, 2021. On July 27, Enforcement Litigation Staff answered Respondents' July 6 answers. On August 23, 2021, the Estate of Andrew Kittell submitted a reply to Enforcement's July 27 answer. This matter is again before the FERC. A previously reported, should the FERC choose to pursue a civil penalty against Respondents for the alleged violations, Respondents have already exercised their right to adjudicate these allegations in federal district court. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

Natural Gas-Related Enforcement Actions

- ***Rover Pipeline, LLC and Energy Transfer Partners, L.P. (IN19-4)***

On March 18, 2021, the FERC issued a show cause order[146] in which it directed Rover Pipeline, LLC ("Rover") and Energy Transfer Partners, L.P. ("ETP" and together with Rover, "Respondents") to show cause why they should not be found to have violated Section 157.5 of the FERC's regulations by misleading the FERC in its Application for Certificate of Public Convenience and Necessity under NGA section 7(c).[147] The FERC directed Respondents to show cause why they should not be assessed civil penalties in the amount of ***$20.16 million***. On April 5, 2021, the FERC extended by 60 days, to June 18, 2021, the deadline for Respondents' answer. On June 18, 2021, Rover and ETP answered the *Rover/ETP Show Cause Order*, asserting that the FERC should dismiss this matter and decline to initiate an enforcement action. On July 21, 2021, Enforcement Staff answered Rover/ETP's answer, stating the evidence supports a finding that Rover violated the FERC's Regulations and should be assessed the civil penalty identified in the *Rover/ETP Show Cause Order*. This matter is pending before the FERC.

- ***BP (IN13-15)***

On December 17, 2020, the FERC issued *Opinion 549-A*,[148] a 159-page decision addressing arguments raised on rehearing requested of *Opinion 549.*[149] *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.[150] Opinion 549-A revised

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

[147] Specifically, Rover stated that it was "committed to a solution that results in no adverse effects" to the Stoneman House, an 1843 farmstead located near Rover's largest proposed compressor station. In truth, the OE Staff Report alleges, Rover was simultaneously planning to purchase the house with the intent to demolish it, if necessary, to complete its pipeline. The OE Staff Report alleges that Rover purchased the house in May 2015 and demolished the house in May 2016. The OE Staff Report further finds that despite taking these actions during the year and a half that Rover's application was pending before the FERC, Rover did not notify the FERC that it purchased the Stoneman House, intended to destroy the Stoneman House, and did destroy the Stoneman House. The OE Staff Report therefore concludes that Rover violated section 157.5's requirement for full, complete and forthright applications, through its misrepresentations and omissions, when it decided not to tell FERC that it had purchased the house and was considering demolishing it, and when Rover demolished it in May 2016 without notifying FERC.

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

[149] *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*")).

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

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.[151]

On December 29, 2020, BP filed a notice that it intends to appeal *Opinion 549-A* to the Fifth Circuit Court of Appeals and paid the civil penalty amount on December 28, 2020, under protest and with full reservation of rights pending the outcome of judicial review of that Opinion. On January 19, BP filed a notice that it disgorged $250,295 ($207,169 principal plus interest), divided equally ($83,431.67) among the following 3 entities identified in the "2016 Comprehensive Energy Assistance Program Subrecipient List": Dallas County Dept. of Health and Human Services (serving Dallas); El Paso Community Action, Project Bravo (Serving El Paso); and Panhandle Community Services (serving Armstrong and numerous other counties), again under protest and with full reservation of rights pending the outcome of judicial review of *Opinion 549/549-A*.

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

On April 28, 2016, the FERC issued a show cause order[152] in which it directed Total Gas & Power North America, Inc. ("TGPNA") and its West Desk traders and supervisors, Therese Tran f/k/a Nguyen ("Tran") and Aaron Hall (collectively, "Respondents") to show cause why Respondents should not be found to have violated NGA Section 4A and the FERC's Anti-Manipulation Rule through a scheme to manipulate the price of natural gas at four locations in the southwest United States between June 2009 and June 2012.[153]

The FERC also directed TGPNA to show cause why it should not be required to disgorge unjust profits of ***$9.18 million***, plus interest; TGPNA, Tran and Hall to show cause why they should not be assessed civil penalties (TGPNA - ***$213.6 million***; Hall - ***$1 million*** (jointly and severally with TGPNA); and Tran - ***$2 million*** (jointly and severally with TGPNA)). In addition, the FERC directed TGPNA's parent company, Total, S.A. ("Total"), and TGPNA's affiliate, Total Gas & Power, Ltd. ("TGPL"), to show cause why they should not be held liable for TGPNA's, Hall's, and Tran's conduct, and be held jointly and severally liable for their disgorgement and civil penalties based on Total's and TGPL's significant control and authority over TGPNA's daily operations. Respondents filed their answer on July 12, 2016. OE Staff replied to Respondents' answer on September 23, 2016. Respondents answered OE's September 23 answer on January 17, 2017, and OE Staff responded to that answer on January 27, 2017.

On July 15, 2021, the FERC issued and order establishing hearing procedures to determine whether Respondents violated the FERC's Anti-Manipulation Rule, and to ascertain certain facts relevant for any application of the FERC's Penalty Guidelines.[154] On July 27, Chief Judge Cintron designated Judge Suzanne Krolikowski as the Presiding ALJ and established an extended Track III Schedule[155] for the proceeding. Judge Krolikowski scheduled and convened on August 26, 2021 a prehearing conference in this proceeding.

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[151] *Id*. at P 319.

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

[153] The allegations giving rise to the Total Show Cause Order were laid out in a September 21, 2015 FERC Staff Notice of Alleged Violations which summarized OE's case against the Respondents. Staff determined that the Respondents violated NGA section 4A and the Commission's Anti-Manipulation Rule by devising and executing a scheme to manipulate the price of natural gas in the southwest United States between June 2009 and June 2012. Specifically, Staff alleged that the scheme involved making largely uneconomic trades for physical natural gas during bid-week designed to move indexed market prices in a way that benefited the company's related positions. Staff alleged that the West Desk implemented the bid-week scheme on at least 38 occasions during the period of interest, and that Tran and Hall each implemented the scheme and supervised and directed other traders in implementing the scheme.

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

[155] The hearing in this proceeding will be convened within 55 weeks (Aug. 15, 2022) and the initial decision issued within 76 weeks (January 9, 2023) of the issuance of the Chief Judge's order.

XIV. Natural Gas Proceedings

For further information on any of the natural gas proceedings, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com).

New England Pipeline Proceedings

The following New England pipeline projects are currently under construction or before the FERC:

- ***Iroquois ExC Project (CP20-48)***
  - 125,000 Dth/d of incremental firm transportation service to ConEd and KeySpan by building and operating new natural gas compression and cooling facilities at the sites of four existing Iroquois compressor stations in Connecticut (Brookfield and Milford) and New York (Athens and Dover).
  - Three-year construction project; service request by November 1, 2023.
  - February 2, 2020 application for a certificate of public convenience and necessity pending; Iroquois requests on January 26, 2021 that the FERC act promptly and issue the certificate; National Grid and ConEd submit comments supporting Iroquois' application and request for action.
  - On May 27, 2021, FERC staff issued a notice that it will prepare an environmental impact statement ("EIS") for this Project, which will respond to comments filed on the Environmental Assessment, and plans to release that EIS on September 3, 3021.
  - On June 11, 2021, FERC staff issued a notice that it has prepared a draft EIS for this Project, which responds to comments on the September 30, 2020 Environmental Assessment, and with the exception of greenhouse gas ("GHG") emissions, concludes that approval of the proposed Project, with the mitigation measures recommended in the EIS, would not result in significant environmental impacts. FERC staff did not come to a determination of significance with regards to GHG emissions. Comments on the draft EIS were due on or before August 9, 2021. Since the last Report, 93 sets of individual comments were filed, bring to nearly 300 the number of individual comments have been filed. Algonquin responded to those comments on August 24, 2021.

- ***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.[156] Rehearing of the *Authorization Order* was timely requested, but denied by operation of law.
  - *Briefing Order*. In a fairly unprecedented order issued February 18, 2021,[157] the FERC, expressing concerns regarding operation of the project, established briefing on the following matters:
    - In light of the concerns expressed regarding public safety, is it consistent with the FERC's responsibilities under the NGA to allow the Weymouth Compressor Station to enter and remain in service?
    - Should the Commission reconsider the current operation of the Weymouth Compressor Station in light of any changed circumstances since the project was authorized? For example, are there changes in the Weymouth Compressor Station's projected air emissions impacts or public safety impacts the Commission should consider? We encourage parties to address how any such changes affect the surrounding communities, including environmental justice communities.

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

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

    - Are there any additional mitigation measures the Commission should impose in response to air emissions or public safety concerns?
    - What would the consequences be if the Commission were to stay or reverse the *Authorization Order*?

- Requests for rehearing of the *Briefing Order* were filed by Algonquin, NGSA and Center for Liquefied Natural Gas, and by America and Energy Infrastructure Council. Cheniere Energy submitted comments in support of the requests for rehearing. On April 19, 2021, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[158] The Notice confirmed that the 60-day period during which a petition for review of its *Briefing Order* can be filed with an appropriate federal court was triggered when the FERC did not act on the requests for rehearing of the *Briefing Order*. The Notice also indicated that the FERC would address, as is its right, the rehearing requests in a future order, and may modify or set aside its orders, in whole or in part, "in such manner as it shall deem proper." On May 19, the FERC issued that order,[159] dismissing the requests for rehearing of the *Briefing Order*, noting, over the objection of Commissioner Danly, that the *Briefing Order* was an exercise of the FERC's continuing oversight of the Project (meaning the claimed harms would be speculative and premature) and Algonquin and Trade Associations will have an opportunity to submit, if they choose, in requests for rehearing of any final decision by the Commission in this proceeding. Algonquin petitioned the DC Circuit for review of the *Briefing Order* and the notice of denial by operation of law on May 3, 2021 (*see* Section XVI below).
- Requests for rehearing of the *May 19 Order* were filed by Algonquin and INGAA. On July 16, 2021, the FERC issued a Notice of Denial of Rehearings by Operation of Law of the requests for rehearing of the *May 19 Order*.
- Algonquin also petitioned the DC Circuit for review of the *Briefing Order*, *April 19 Notice of Denial of Rehearings by Operation of Law*, and the *May 19 Order*.[160]
- This matter is before the DC Circuit (*see* Section XVI below).

Non-New England Pipeline Proceedings

The following pipeline projects could affect ongoing pipeline proceedings in New England and elsewhere:

- **Northern Access Project (CP15-115)**
    - The New York State Department of Environmental Conservation ("NY DEC") and the Sierra Club requested rehearing of the *Northern Access Certificate Rehearing Order* on August 14 and September 5, 2018, respectively. On August 29, National Fuel Gas Supply Corporation and Empire Pipeline ("Applicants") answered the NY DEC's August 14 rehearing request and request for stay. On April 2, 2019, the FERC denied the NY DEC and Sierra Club requests for rehearing.[161] 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*.[162] 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

[158] *Algonquin Gas Transmission, LLC and Maritimes & Northeast Pipeline, LLC*, 175 FERC ¶ 62,022 (Apr. 19, 2021) ("*April 19 Notice of Denial of Rehearings by Operation of Law*").

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

[160] *Algonquin Gas Transmission, LLC and Maritimes & Northeast Pipeline, LLC*, 176 FERC ¶ 62,029 (July 16, 2021) ("*July 16 Notice of Denial of Rehearings by Operation of Law*").

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

[162] *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).

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,[163] 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.[164] The Allegheny Defense Project and Sierra Club (collectively, "Allegheny") requested rehearing of the *Northern Access Certificate Order*.
- Despite the FERC's *Northern Access Certificate Order*, the project remained halted pending the outcome of National Fuel's fight with the NY DEC's April denial of a Clean Water Act permit. NY DEC found National Fuel's application for a water quality certification under Section 401 of the Clean Water Act, as well as for stream and wetlands disturbance permits, failed to comply with water regulations aimed at protecting wetlands and wildlife and that the pipeline failed to explore construction alternatives. National Fuel appealed the NY DEC's decision to the 2nd Circuit on the grounds that the denial was improper.[165] 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,[166] 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.[167]
- 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, [168] finding the request premature. The FERC reiterated its encouragement that pipeline applicants requesting

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[163] 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).

[164] *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*").

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

[166] 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).

[167] *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).

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

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.[169]

XV. State Proceedings & Federal Legislative Proceedings

- **New England States' Vision Statement**

In October 2020, the six New England states released their "Vision Statement", outlining their vision for "a clean, affordable, and reliable 21st century regional electric grid" and committing to engage in a collaborative and open process, supported by NESCOE, intended to advance the principles discussed in the Vision Statement. As part of that effort, the following series of online technical forums to discuss the issues presented in the Vision Statement were held:

Jan 13, 2021	Wholesale Market Reform
Jan 25, 2021	Wholesale Market Reform
Feb 2, 2021	Transmission Planning
Feb 25, 2021	Governance Reform
Mar 18, 2021	Equity and Environmental Justice

Written comments on the topics and discussions addressed in the on the equity and environmental justice topics and discussions were, following an extension, due by May 13, 2021. Comments submitted are posted on **NewEnglandEnergyVision.com**. Recordings of the technical forums, as well as draft notices, agendas, and additional information on these sessions, are also available on the New England States' Vision Statement website (https://newenglandenergyvision.com/).

Report to the Governors. On June 29, 2021, the NESCOE Managers published their Progress Report to the New England Governors Regarding "Advancing the New England Energy Vision". The Report will be further discussed at the August 5, 2021 Participants Committee meeting. View Report here.

XVI. Federal Courts

The following are matters of interest, including petitions for review of FERC decisions in NEPOOL-related proceedings, that are currently pending before the federal courts (unless otherwise noted, the cases are before the U.S. Court of Appeals for the District of Columbia Circuit). An "**" following the Case No. indicates that NEPOOL has intervened or is a litigant in the appeal. The remaining matters are appeals as to which NEPOOL has no organizational interest but that may be of interest to Participants. For further information on any of these proceedings, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **ISO-NE Implementation of Order 1000 Exemptions for Immediate Need Reliability Projects (20-1422)**
  Underlying FERC Proceeding: EL19-90[170]
  Petitioner: LS Power
  Status: Briefing Complete; Pending Court Action

On October 16, 2020, LSP Transmission Holdings II, LLC ("LS Power") petitioned the DC Circuit Court of Appeals for review of the FERC's orders addressing ISO-NE's implementation of the Order 1000 exemptions for

[169] *Id.* at P 10.

[170] *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 projects. Since the last Report, MMWEC filed on July 8 a notice that it would not submit a Reply Brief. On July 9, 2021, LSP Transmission filed Petitioner's Reply Brief. LSP Transmission filed a Joint Appendix on July 16. On July 28, 2021, MMWEC filed an Intervenor for Petitioner Final Brief. Final Briefs were filed on July 30. Briefing is now complete and this matter is pending before the Court

- **CIP IROL Cost Recovery Rules (20-1389)**
  Underlying FERC Proceeding: ER20-739[171]
  Petitioner: Cogentrix, Vistra
  Status: Briefing Complete; Pending Court Action

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. Since the last Report, Cogentrix and Vistra filed a Deferred Appendix (July 16, 2021) and Final Briefs (from Petitioners and the FERC) were submitted on July 26, 2021. Briefing is now complete and this matter is pending before the Court.

- **Mystic 8/9 Cost of Service Agreement (20-1343; 20-1361, 20-1362; 20-1365, 20-1368; 21-1067; 21-1070)(consolidated)**
  Underlying FERC Proceeding: EL18-1639[172]
  Petitioners: Mystic (20-1343), NESCOE (20-1361, 21-1067), MA AG (20-1362), CT Parties (20-1365, 20-1368, 21-1070)
  Status: Briefing Not Yet Begun

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.[173] The cases have been consolidated into Case No. 20-1343. On February 17 and 24, 2021, the Court consolidated with 20-1343 the most recent appeals in cases 21-1067 (NESCOE) and 21-1070 (CT Parties), respectively. On March 25, 2021, the Court issued an order returning this case to its active docket. On March 26, the Court granted the interventions by MMWEC/NHEC, NESCOE, and ENECOS. On April 16, 2021, the Court ordered the parties to file, and the parties did file, by May 17, 2021, proposed formats for the briefing of these cases.

On June 23, 2021, the Court established a briefing schedule that calls for the following: Mystic and State Petitioners' Opening Briefs (September 7, 2021); Intervenor for State Petitioners' Brief (September 21, 2021); Respondent's Brief (December 6, 2021); Intervenors for Respondents' Briefs (December 20, 2021); Reply Briefs (February 3, 2022); Joint Appendix (February 17, 2022); and Final Briefs (February 24, 2022). The date for oral argument and the composition of the merits panel will be identified at a later time. Since the last Report, on July 12, the FERC filed a Certified Index to the Record.

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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).

[171] *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*").

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

[173] 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.

- ***CASPR* (20-1333, 20-1331) (consolidated)****
  Underlying FERC Proceeding: ER18-619[174]
  Petitioners: Sierra Club, NRDC, RENEW Northeast, and CLF
  Status: Being Held in Abeyance

On August 31, 2020, the Sierra Club, NRDC, RENEW Northeast, and CLF petitioned the DC Circuit Court of Appeals for review of the FERC's order accepting ISO-NE's CASPR revisions (which, under *Allegheny*, is ripe for review). On October 2, 2020, appearances, docketing statements, a statement of issues to be raised, and a statement of intent to utilize deferred joint appendix were filed. On October 19, 2020, the FERC moved to dismiss the case for a lack of jurisdiction (arguing that Petitioners missed their opportunity to timely file their Petition for review in 2018, and filing within 60 days of *Allegheny* did not make their Petition timely). Alternatively, the FERC asked that the case be held in abeyance for 60 days pending issuance of a further FERC order on this matter. On October 29, Petitioners opposed the FERC's motion. On November 5, 2020, the FERC filed a reply, indicated that an order on rehearing would be issued imminently and suggested that, if the Court declines to dismiss the petition, it should be held in abeyance until the Commission issues an order on rehearing. As noted above, the FERC issued the *CASPR Allegheny Order* on November 19, modifying the discussion in the *CASPR Order*, but reaching the same the result. The Sierra Club, NRDC and CLF also requested rehearing of the November 19 order.

On January 12, 2021, the Court dismissed as moot the FERC's October 19 motion to hold this proceeding in abeyance and ordered that the motion to dismiss be referred to the merits panel (Judges Pillard, Katsas and Walker) and addressed by the parties in their briefs. On January 25 and 26, CT Parties and MMWEC and NHEC filed statements of issues and notices that they intend to participate in support of Petitioners. On January 27, the Court ordered the parties to submit by February 26, 2021, proposed formats for the briefing of these cases. On March 24, 2021, the Court granted NEPOOL's intervention and established a briefing schedule that, as explained just below, has since been superseded.

On April 7, 2021, the Court granted Petitioners' motion to hold this matter in abeyance, pending further order of the Court. The parties were directed to file motions to govern future proceedings in these cases on or before October 22, 2021.

- ***Opinion 531-A* Compliance Filing Undo (20-1329)**
  Underlying FERC Proceeding: ER15-414[175]
  Petitioners: TOs' (CMP et al.)
  Status: Being Held in Abeyance

On August 28, 2020, the TOs[176] 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*[177] 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

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

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

[176] 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.

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

in which the challenged order was issued remains ongoing before the FERC. Petitioners consented to the requested abeyance. On February 11, 2021, the Court issued an order that that this case remain in abeyance pending further order of the court. On April 21, 2021, the FERC filed an unopposed motion for continued abeyance of this case *because* the Commission intends to issue a future order on Petitioners' request for rehearing of the challenged Order Rejecting Compliance Filing, and because the remand proceeding in which the challenged order was issued remains ongoing.

On May 4, *2021*, the Court ordered that this case remain in abeyance pending further order of the court, directing the FERC to file a status report by September 1, 2021 and at 120-day intervals thereafter. The parties were directed to file motions to govern future proceedings in this case within 30 days of the completion of agency proceedings. On August 24, the FERC submitted a status report indicating that the proceedings before the Commission remain ongoing and that this appeal should continue to remain in abeyance.

- **2013/14 Winter Reliability Program Order on Compliance and Remand (20-1289, 20-1366) (consol.) Underlying FERC Proceeding: ER13-2266**[178]
  Petitioner: TransCanada
  Status: Briefing Complete; Pending Court Action

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*.[179] NEPGA intervened on October 15, 2020 (and its intervention granted on October 28). On October 16, TransCanada filed a docketing statement and statement of issues. On October 29, the FERC filed a certified index to the record and an unopposed motion for a 60-day briefing period. On December 2, 2020, the Court granted the FERC's October 29 motion On January 11, 2021, TransCanada submitted its initial brief. On March 12, FERC filed its Respondent Brief. Since the last Report, TransCanada filed Petitioner's Reply Brief on April 9, 2021 and the Deferred Appendix on April 16. TransCanada filed its Final Brief on April 30, 2021. Briefing is now complete. On August 6, the Court scheduled oral argument for Friday, October 15, 2021. The composition of the argument panel will be revealed on or about September 15, 2021 on the court's web site at www.cadc.uscourts.gov.

- **ISO-NE's Inventoried Energy Program (Chapter 2B) Proposal (19-1224***; 19-1247; 19-1252; 19-1253)(consolidated); Underlying FERC Proceeding: ER19-1428**[180]
  Petitioners: ENECOS (Belmont et al.) (19-1224); MA AG (19-1247); NH PUC/NH OCA (19-1252); Sierra Club/UCS (19-1253)
  Status: Briefing Complete; Pending Court Action

As previously reported, at the unopposed request of the FERC, the Court issued an order suspending the previous briefing schedule and remanding the record back to the FERC. Subsequently, the FERC issued its *IEP Remand Order* (June 18, 2020) and its Notice of Denial by Operation of Law of the requests for rehearing of its *IEP Remand Order* (August 20, 2020). As previously reported, each of the Petitioners filed amended petitions for review in the consolidated proceeding in order to bring the FERC's *IEP Remand Order* and the post-remand FERC record before the DC Circuit. On November 10, 2020, the Court ordered that the cases be removed from abeyance. Opening Briefs from Petitioners were filed on December 11, 2020. The FERC filed its Respondent Brief on February 9. Intervenor for Respondent Briefs were filed on February 16 by ISO-NE and NEPGA. On February 24, the FERC filed an amended certified index to the record. Petitioners' Reply Brief was filed on March 30, 2021.

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[178] 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*").)

[179] 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.

[180] 162 FERC ¶ 61,127 (Feb. 15, 2018) ("*Order 841*"); 167 FERC ¶ 61,154 (May 16, 2019) ("*Order 841-A*").

The Deferred Appendix was filed on April 20, 2021. Final Briefs were filed on May 4, 2021. Briefing is now complete. On August 6, 2021, the Court scheduled oral argument for Thursday, October 21, 2021. The composition of the argument panel will be revealed on or about September 21, 2021 on the court's web site at www.cadc.uscourts.gov.

Other Federal Court Activity of Interest

- ***Order 872* (20-72788,* 21-70113; 20-73375, 21-70113) (consol.) (9th Cir.)**
  Underlying FERC Proceeding: RM19-15[181]
  Petitioners: SEIA et al.
  Status: Briefing Again Underway

On September 17, 2020, SEIA petitioned the 9th Circuit Court of Appeals for review of *Order 872*.[182] On October 9, the FERC filed an unopposed motion for the Court to hold this appeal in abeyance, suspend filing of the certified index to the record, and issue a new briefing schedule after January 4, 2021. The abeyance was to permit the FERC to address the pending rehearing requests in a future order. On October 26, 2020, the Court granted the FERC's motion. On January 29, 2021, SEIA requested that this case be consolidated with the others, and that the abeyance period be extended to give the parties additional time to coordinate and develop a unified, efficient briefing schedule.

On March 25, 2021, the Court granted SEIA's unopposed March 5, 2021 motion to lift the stay in this proceeding. Briefing has resumed. On May 27, 2021, Petitioners' briefs were filed by SEIA and Other Petitioners.[183] On June 28, 2021, petitioner-intervenors filed their joint brief and (June 28, 2021); motions and associated briefs by amici curiae in support of petitioners were also filed on June 28, 2021. Since the last Report, NewSun Energy filed an Intervenor Brief on July 28. Next up will be Respondent's brief (September 27, 2021); joint brief of respondent-intervenors (October 27, 2021); motions and associated briefs by amici curiae in support of respondent (October 27, 2021); and any optional reply briefs (December 13, 2021).

- **PennEast Project (18-1128)**
  Underlying FERC Proceeding: CP15-558[184]
  Petitioners: NJ DEP, DE and Raritan Canal Commission, NJ Div. of Rate Counsel
  Status: Being Held in Abeyance

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")[185] for the construction and operation of a new 116-mile natural gas pipeline from Luzerne County, Pennsylvania, to Mercer County, New Jersey, along with three laterals extending off the mainline, a compression station, and appurtenant above ground facilities ("PennEast Project"). The cases are being held in abeyance "pending final disposition of any post-dispositional proceedings [ ] before the United States Supreme Court resulting from the Third Circuit's decision in No. 19-1191 (In re: PennEast Pipeline Company, LLC (3rd Cir. Sep. 10, 2019)), or other action that resolves the obstacle

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[181] *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).

[182] *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.

[183] "Other Petitioners" are Montana Environmental Information Center, Sierra Club, Center for Biological Diversity, Vote Solar, Appalachian Voices, Energy Alabama, Georgia Interfaith Power & Light, North Carolina Sustainable Energy Association, Upstate Forever, and Community Renewable Energy Association.

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

[185] 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.

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 June 22, 2021, noting developments since the March 23, 2021 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) (consol.)**
  Underlying FERC Proceeding: EL14-12; EL15-45[186]
  Petitioners: MISO TOs, Transource Energy, Dec 23 Petitioners et al.
  Status: Briefing Complete; Pending Court Action

The MISO Transmission Owners (TOs), Transource and "Dec 23 Petitioners",[187] among others, have appealed *Opinion 569/569-A*. The MISO TOs' case has been consolidated with previous appeals that had been held in abeyance, with the lead case number assigned as 16-1325. The FERC filed a certified Index to the Record on December 3, 2020, the Parties filed a joint unopposed briefing schedule on December 23, 2020. Statements of issues were filed on February 8, 2021. Petitioners' Briefs were filed on March 10. On March 17, 2021, a motion to participate as amicus curiae was jointly filed by NEP, CPM, Eversource, Fitchburg and Unitil, NHT, VTransco, Versant Power, and UI ("New England Parties") (that motion was granted on April 30, 2021). On March 18, New England Parties submitted an amicus brief in support of Transmission Owning Petitioners. On March 24, 2021, Intervenors in Support of Petitioners[188] filed their Brief. FERC filed its Respondent brief on June 8 and Intervenors in Support of FERC their Joint Brief on June 22, 2021. Petitioners' and Joint Petitioners' Reply Briefs were filed on July 8, 2021; Intervenors in Support of Petitioners Reply Briefs, July 22, 2021. Since the last Report, the Joint Deferred Appendix was filed on August 5, 2021; Final Briefs on August 19, 2021. Briefing is now complete and this matter is before the Court.

- **Algonquin Atlantic Bridge Project Briefing Order (21-1115*, 21-1138, 21-1153, 21-1155) (consol.);**
  Underlying FERC Proceeding: CP16-9-012[189]
  Petitioners: LS Power, Algonquin, INGA
  Status: Case Being Held in Abeyance

On May 3, 2021, Algonquin petitioned the DC Circuit Court of Appeals for review of the *Briefing Order* and the *April 19 Notice of Denial of Rehearings by Operation of Law*. Appearances, docketing statements and a statement of issues were due and filed June 4, 2021. Also on June 4, 2021, the FERC filed an unopposed motion to hold this proceeding in temporary abeyance, until August 2, 2021, including the fling of the certified index to the record, because "the May 3 petition for review no longer reflects the [FERC]'s latest determination in this matter." The Court granted the first abeyance motion. On August 27, 2021, the Court granted a second abeyance motion by the FERC, directing the parties to file motions to govern future proceedings by October 29, 2021.

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[186] *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).

[187] "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.

[188] The Intervenors for Petitioners Brief was filed by Citizens Utility Board of Wisconsin, Illinois Citizens Utility Board, Indiana Office of Utility Consumer Counselor, Iowa Office of Consumer Advocate, Louisiana Public Service Commission, Michigan Citizens Against Rate Excess, Minnesota Department of Commerce, and Missouri Office of Public Council.

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

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