NEW ENGLAND POWER POOL

David T. Doot
Secretary

June 14, 2022

VIA ELECTRONIC MAIL

TO: MEMBERS AND ALTERNATES OF THE NEPOOL PARTICIPANTS COMMITTEE

RE: Supplemental Notice of June 21-23, 2022 NEPOOL Participants Committee Summer Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that the NEPOOL Participants Committee Summer Meeting will be held on June 21-23, 2022 at The Samoset Resort in Rockport, ME. Please see the attached meeting agenda and Sector meeting schedule, which are also posted with the meeting materials. Plenary sessions will be in the Knox County Ballroom.[1] If you cannot make the meeting in person, telephone participation will be available for the plenary sessions (and to a more limited extent for the separate meetings of the Sectors). Please contact us for the dial-in information; it will be provided in advance of the meeting.

Also in advance of the Summer Meeting, we hope those who arrive on Monday will join your colleagues at a dessert/coffee reception from 8:00-10:00 p.m. on the Penobscot Bay Patio (weather permitting) or in the Bay Point Ballroom. As reflected on the meeting agenda, the general NEPOOL business will be conducted on Tuesday, with a planned 9:30 a.m. start. Note that Tuesday's agenda includes the annual presentation by the ISO's External Market Monitor. Wednesday's session is planned to begin at 9:00 a.m., and will include remarks from FERC Commissioner Mark Christie followed by a panel discussion with representatives from the New England States on the future grid pathways. Wednesday afternoon is set aside for separate meetings or participation in networking events. Thursday's session is for modified Sector group meetings, scheduled to begin at 8:00 a.m., with times set aside for each group to meet separately with State Officials, ISO Board members, and if and as interested, with FERC staff. ***Please note the times and rooms where your modified Sector group is scheduled to meet.*** Additional information regarding the Summer Meeting is available on the Summer Meeting information page.

The NEPOOL reservations block at The Samoset is now closed. If you are still in need of a room, please contact Kathryn Dube who may be able to assist getting you into The Samoset or an alternative venue/inn if possible. **For those staying at The Samoset, please note that the check-in time is 4:00 p.m. and the check-out time is 11:00 a.m. The cancellation policy is 7 days prior to the first day of your reservation. Dress for the Summer Meeting is business casual.** Looking forward to seeing so many of you in person next week.

Respectfully yours,

/s/
David T. Doot, Secretary

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

FINAL AGENDA

TUESDAY, JUNE 21, 2022
9:30 a.m. – 4:30 p.m.* General Session

1. [~~To approve the preliminary minutes of the Participants Committee meetings held on April 26 (Future Pathways) and May 5, 2022.~~] Deferred to August 4, 2022 meeting.

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

2A. To consider and approve, as appropriate, proposed Tariff revisions recommended by the Markets Committee (MC) to allow storage resources that inject energy into the grid but do not receive energy from the grid to register and operate as a Continuous Storage Facility that, but for the timing of the MC's action, would have been on the Consent Agenda. Background material and a draft resolution are included and posted with this supplemental notice.

3. To receive a Chief Executive Officer Report by Gordon van Welie, ISO New England.

4. To receive a Chief Operating Officer Report by Dr. Vamsi Chadalavada, ISO New England, including information concerning the upcoming winter. A presentation on the ISO's roadmap for some of its longer-term plans for meeting the clean energy future is included and posted with this supplemental notice.

5. To receive a report on the ISO's preliminary 2023 and 2024 Operating and Capital Budgets by Chief Financial & Compliance Officer Robert Ludlow, ISO New England. Background materials are included and posted with this supplemental notice.

6. To receive a report on current matters relating to regional wholesale power and transmission arrangements that are pending before the regulators and the courts. A Litigation Report will be circulated and posted in advance of the meeting.

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

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

7A. FERC staff introduction.

8. To receive an External Market Monitor Report by Dr. David Patton, President, Potomac Economics. A copy of the EMM's 2021 Annual Report on the ISO New England Markets is posted on the NEPOOL website. A presentation with highlights of the EMM's 2021 Annual Report will be circulated and posted following receipt.

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

*All start and finish times subject to adjustment.

WEDNESDAY, JUNE 22, 2022
9:00 a.m. – 12:00 p.m.*

10. To receive welcome remarks.

11. To receive remarks from FERC Commissioner Mark Christie.

12. Panel of New England State Regulators and Officials to share perspectives on future grid pathways followed by discussion of the same. Panelists will include:

    - CT: Katie Dykes, Commissioner, Connecticut Department of Energy & Environmental Protection (virtual)
    - ME: Phil Bartlett, Chair, Maine Public Utilities Commission (in person)
    - MA: Matt Nelson, Chair, Massachusetts Department of Public Utilities (virtual)
    - MA: Patrick Woodcock, Commissioner, Massachusetts Dept. of Energy Resources (in person)
    - NH: Dan Phelan, Utility Analyst, IV, New Hampshire Department of Energy (in person)
    - VT: June Tierney, Commissioner, Vermont Department of Public Service (virtual)

Wednesday afternoon has been set aside for separate meetings and organized networking as desired

THURSDAY, JUNE 23, 2022
8:00 a.m. – 12:15 p.m.*

The last day of the Summer Meeting has been set aside for separate, modified Sectors meetings with individual ISO Board Members, State Officials and FERC Staff, as detailed in the Sector meeting schedule included with this final agenda.

*All start and finish times subject to adjustment.

CONSENT AGENDA

Transmission Committee (TC)

From the previously-circulated notice of actions of the TC's May 31, 2022 meeting, dated May 31, 2022.[1]

1. **Changes to OATT Schedules 23-25 (Interconnection Jurisdiction for Distribution-Connected Generating Facilities)**

   Support revisions to OATT Schedules 22 (Standard Large Generator Interconnection Procedures), 23 (Standard Small Generator Interconnection Procedures) and 25 (Standard Elective Transmission Upgrade Interconnection Procedures) to identify that all new distribution-connected generation should proceed through the state interconnection process, as recommended by the TC at its May 31, 2022 meeting, together with such further non-material changes as the Chair and Vice-Chair of the TC may approve.

   The motion to recommend Participants Committee support was unanimously approved, with 1 abstention noted in each of the Transmission and End User Sectors.

2. **Changes to OATT Schedule 18 and Incorporation of New Attachment Q (Order 881 [Managing Transmission Line Ratings] Compliance Changes)**

   Support revisions to OATT Schedule 18 (Standard Large Generator Interconnection Procedures) and the incorporation of a new OATT Attachment Q () in response to Order 881's directive to incorporate the use of Ambient Adjusted Ratings (AARs) for transmission lines, as recommended by the TC at its May 31, 2022 meeting, together with such further non-material changes as the Chair and Vice-Chair of the TC may approve.

   The motion to recommend Participants Committee support was unanimously approved, with 1 abstention noted in each of the Transmission and End User Sectors.

Reliability Committee (RC)

From the previously-circulated notice of actions of the RC's May 16, 2022 meeting, dated May 17, 2022.[2]

3. **Changes to OP-22, Including Appendices A-C (Periodic Updates and New Appendix C)**

   Support the revisions to ISO New England Operating Procedure No. 22 (OP-22) (Disturbance Monitoring Requirements), including general updates to OP-22, the listing of an additional facility in confidential Appendices A & B, and the addition of Appendix C (New England PMU Registration), as recommended by the RC at its May 16, 2022 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.

[Continued on next page]

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

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

Markets Committee (MC)

From the previously-circulated notice of actions of the MC's May 10, 2022 meeting, dated May 10, 2022.[3]

4. <u>Information Policy and Tariff Definition Revisions (Cyber Security Incident Information Sharing)</u>

Support the revisions to (i) Section 3.2 of Attachment D of the Tariff to meet mandatory cyber security reporting requirements and (ii) Section I.2.2 of the Tariff to modify confidentiality restrictions when the ISO is reporting cyber security incidents and events to certain federal agencies, as recommended by the MC at its May 10, 2022 meeting, together with such further non-material changes as the Chair and Vice-Chair of the MC may approve.

The motion to recommend Participants Committee support was unanimously approved.

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

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Sebastian Lombardi and Rosendo Garza, Jr., NEPOOL Counsel

DATE: June 14, 2022

RE: MC-Recommended Revisions to the Continuous Storage Facility Model

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At its June 21–23, 2022 summer meeting, the Participants Committee will be asked to support ISO-proposed Tariff revisions to allow storage resources that inject energy into the grid but do not receive energy from the grid to register and operate as a Continuous Storage Facility (CSF). The Markets Committee reviewed and unanimously recommended that the Participants Committee support those changes (referred to herein as the CSF Model Revisions). But for the timing of the Markets Committee's action on the CSF Model Revisions, this matter would have been on the Consent Agenda for next week's meeting.

Included with this memorandum are the ISO-NE voting memorandum (Attachment A) and the proposed Tariff redlines (Attachment B).

OVERVIEW OF CSF MODEL REVISIONS & MC CONSIDERATION

The CSF Model Revisions are two-fold: (1) modifying Sections III.1.10.6 and III.1.10.6(a)(vi) to Market Rule 1 to include a storage facility that cannot receive electricity from the grid; and (2) adding a new subsection (i.e., Section III.1.10.6(d)), which allows storage resources to register and operate as a CSF without needing to consume charging energy from the grid.

At its June 8, 2022 meeting, the Markets Committee considered and unanimously recommended Participants Committee support for the proposed CSF Model Revisions, with one abstention registered in the Supplier Sector. As noted, these revisions would have been on the Consent Agenda for the June 21 meeting but for the timing of the Markets Committee's vote.

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

> RESOLVED, that the Participants Committee supports the revisions to Section III.1.10.6 of the Tariff pertaining to storage resources operating as Continuous Storage Facilities, as recommended by the Markets Committee and as circulated in advance of this meeting, together with such further non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

memo

To: NEPOOL Markets Committee ("MC")

From: Doug Smith, Technical Manager

Date: June 1, 2022

Subject: Continuous Storage Facility ("CSF") Model Improvement (WMPP ID: 165)

The ISO is requesting a vote on proposed revisions to Section III.1.10.6 of Market Rule 1 to improve the CSF model.

The ISO proposes to modify the Tariff to allow storage resources to register and operate as a CSF even if they cannot consume energy from the grid, which will allow inject-only storage resources to provide all the wholesale market services they are capable of providing. In addition, this will provide the ISO greater visibility and dispatch control on these facilities than alternative options for inject-only storage resource participation.

This topic was first presented to the Markets Committee at its May 10, 2022 meeting (agenda item 4). The specific proposal for the committee's consideration at its June 7-8, 2022 meeting includes changes that are responsive to stakeholder feedback received during and subsequent to that meeting.

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MC-Recommended Tariff Revisions to the Continuous Storage Facility Model

III.1.10.6 Electric Storage

A storage facility is a facility that is capable of receiving electricity ~~from the grid~~ and storing the energy for later injection of electricity ~~back~~ into the grid. A storage facility may participate in the New England Markets as described below.

(a) A storage facility that satisfies the requirements of this subsection (a) may participate in the New England Markets as an Electric Storage Facility. An Electric Storage Facility shall:

- (i) comprise one or more storage facilities at the same point of interconnection;
- (ii) have the ability to inject at least 0.1 MW and consume at least 0.1 MW;
- (iii) be directly metered;
- (iv) be registered as, and subject to all rules applicable to, a dispatchable Generator Asset;
- (v) be registered as, and subject to all rules applicable to, a DARD that represents the same equipment as the Generator Asset;
- (vi) settle its injection of electricity to the grid as a Generator Asset and any~~its~~ receipt of electricity from the grid as a DARD;
- (vii) not be precluded from providing retail services so long as it is able to fulfill its wholesale Energy Market and Forward Capacity Market obligations including, but not limited to, satisfying meter data reporting requirements and notifying the ISO of any changes to operational capabilities; and
- (viii) meet the requirements of either a Binary Storage Facility or a Continuous Storage Facility, as described in subsections (b) and (c) below.

(b) A storage facility that satisfies the requirements of this subsection (b) may participate in the New England Markets as a Binary Storage Facility. A Binary Storage Facility shall:

- (i) satisfy the requirements applicable to an Electric Storage Facility; and
- (ii) offer its Generator Asset and DARD into the Energy Market as Rapid Response Pricing Assets; and
- (iii) be issued Dispatch Instructions in a manner that ensures the facility is not required to consume and inject simultaneously.

(c) A storage facility that satisfies the requirements of this subsection (c) may participate in the New England Markets as a Continuous Storage Facility. A Continuous Storage Facility shall:

(i) satisfy the requirements applicable to an Electric Storage Facility;

(ii) be registered as, may provide Regulation as, and is subject to all rules applicable to, an ATRR that represents the same equipment as the Generator Asset and DARD;

(iii) be capable of transitioning between the facility's maximum output and maximum consumption (and vice versa) in ten minutes or less;

(iv) not utilize storage capability that is shared with another Generator Asset, DARD or ATRR;

(v) specify in Supply Offers a zero MW value for Economic Minimum Limit and Emergency Minimum Limit (except for Generator Assets undergoing Facility and Equipment Testing or auditing); a zero time value for Minimum Run Time, Minimum Down Time, Notification Time, and Start-Up Time; and a zero cost value for Start-Up Fee and No-Load Fee;

(vi) specify in Demand Bids a zero MW value for Minimum Consumption Limit (except for DARDs undergoing Facility and Equipment Testing or auditing) and a zero time value for Minimum Run Time and Minimum Down Time;

(vii) be Self-Scheduled in the Day-Ahead Energy Market and Real-Time Energy Market, and operate in an on-line state, unless the facility is declared unavailable by the Market Participant; and

(viii) be issued a combined dispatch control signal equal to the Desired Dispatch Point (of the Generator Asset) minus the Desired Dispatch Point (of the DARD) plus the AGC SetPoint (of the ATRR).

(d) A storage facility incapable of receiving and storing electricity from the grid may participate in the New England Markets as a Continuous Storage Facility, so long as that facility satisfies all Continuous Storage Facility registration and participation requirements that are not solely related to consumption capability. Notwithstanding Section III.1.10.6(a), Section III.1.10.6(c), and any other related provisions, such non-consuming storage facilities shall not be required to:

(i) be capable of consuming at least 0.1 MW from the grid; and

(ii) be capable of modifying consumption responsive to Dispatch Instructions.

~~(d)~~(e) A storage facility shall comply with all applicable registration, metering, and accounting rules including, but not limited to, the following:

(i) A Market Participant wishing to purchase energy from the ISO-administered wholesale markets must first, jointly with its Host Participant, register one or more wholesale Load Assets with the ISO as described in ISO New England Manual M-28 and ISO New

England Manual M-RPA; where the Market Participant wishes to register an Electric Storage Facility, the registered Load Asset must be a DARD.

(ii) A storage facility's charging energy shall not qualify as, or be billed to, a Storage DARD if that facility's charging energy is included in another Load Asset. A storage facility registered as a DARD will be charged the nodal Locational Marginal Price by the ISO and the Market Participant will not pay twice for the same charging energy.

(iii) The registration and metering of all Assets must comply with ISO New England Operating Procedure No. 14 and ISO New England Operating Procedure No. 18, including with the requirement that an Asset's revenue metering must comply with the accuracy requirements found in ISO New England Operating Procedure No. 18.

(iv) Pursuant to ISO New England Manual M-28, the Assigned Meter Reader, the Host Participant, and the ISO provide the data for use in the daily settlement process within the timelines described in the manual. The data may be five-minute interval data, and may be no more than hourly data, as described in Section III.3.2 and in ISO New England Manual M-28.

(v) Based on the Metered Quantity For Settlement and the Locational Marginal Price in the settlement interval, the ISO shall conduct all Energy Market accounting pursuant to Section III.3.2.1.

~~(e)~~(f) A facility registered as a dispatchable Generator Asset, an ATRR, and a DARD that each represent the same equipment must participate as a Continuous Storage Facility.

~~(f)~~(g) A storage facility not participating as an Electric Storage Facility may, if it satisfies the associated requirements, be registered as a Generator Asset (including a Settlement Only Resource) for settlement of its injection of electricity to the grid and as an Asset Related Demand for settlement of its wholesale load.

~~(g)~~(h) A storage facility may, if it satisfies the associated requirements, be registered as a Demand Response Asset. (As described in Section III.8.1.1, a Demand Response Asset and a Generator Asset may not be registered at the same end-use customer facility unless the Generator Asset is separately metered and reported and its output does not reduce the load reported at the Retail Delivery Point of the Demand Response Asset.)

~~(h)~~(i) A storage device may, if it satisfies the associated requirements, be registered as a component of either an On-Peak Demand Resource or a Seasonal Peak Demand Resource.

~~(i)~~(j) A storage facility may, if it satisfies the associated requirements, provide Regulation pursuant to Section III.14.

Summary of ISO New England Board and Committee Meetings

June 21-23, 2022 Participants Committee Meeting

Since the last update, the Audit and Finance Committee, the Markets Committee, and the Nominating and Governance Committee met on May 19. The Board of Directors met on May 18 and 19. All meetings were held in Boston, Massachusetts. The Markets Committee also met by video conference on May 11 and June 3.

The Audit and Finance Committee reviewed the Company's financial performance against the 2022 budget, and approved the first quarter's unaudited financial statements after management confirmed that all relevant disclosures were included in the financial statements. Next, the Committee discussed the preliminary 2023 operating and capital budgets, and the need for increases (including headcount) in order to address the region's priorities, safeguard against evolving cyber threats, recruit and retain a highly skilled workforce, and manage related capital projects. Next, the Committee discussed management's analysis of the financial impacts of the February 2021 winter storm in the ERCOT markets to assess whether the New England markets were similarly at risk. The Committee noted, based on several stress test scenarios, that the collateral requirements in the Company's Financial Assurance Policy largely protect against substantial defaults in similar situations. The Committee reviewed the annual vendor report, which showed the top fifteen vendors and a comparison to the previous period. Finally, the Committee reviewed a draft of the Company's 2021 tax return on Form 990.

The Markets Committee met on May 11 and reviewed the Internal Market Monitor's draft annual markets report for 2021, and discussed the recommendations that will be contained in the report. At its meeting on May 19, the Committee provided final comments on the Internal Market Monitor's draft annual markets report, and received an overview of the highlights of the External Market Monitor's 2021 annual markets report. Next, the Committee was also provided with a market monitoring review of market performance in winter 2021-2022. The Committee then received an update on the resource capacity accreditation project and the day-ahead ancillary services project. At its meeting on June 3, the Committee discussed winter reliability issues and a range of potential options to mitigate risks to reliability for the 2022-2023 winter. The Committee also reviewed a draft of the External Market Monitor's 2021 annual markets report, discussed the comparison of key market metrics to those of other regional markets, and asked a number of clarifying questions.

The Nominating and Governance Committee discussed the schedule for the orientation of director-elect Melvin Williams, the Joint Nominating Committee process for 2023, and discussed challenges related to the Board age limit. The Committee also discussed assignments to Board committees and succession planning for board leadership positions. The Committee discussed the logistics and agenda for the 2022 open Board meeting, including topics for an outside speaker. In executive session, the Committee reviewed the Board and committees' self-evaluation responses.

The Board of Directors met on May 18 for an in-depth review of the Company's strategic plan. The Board discussed each of the four pillars that are necessary components to ensure a reliable bulk power system, and the organization of the strategic plan around those elements. The Board noted that many aspects of those pillars are out of the ISO's control, particularly as it relates to sufficiency of fuel supply infrastructure and the siting and development of transmission and new supply resources. On May 19, the Board recapped its strategic planning discussions. The Board also considered steps to finalize its response to the New England states' request for governance improvements. Lastly, the Board considered topics for discussion with the NEPOOL sectors in June, and agreed that the sectors should determine the agendas for the meeting.

2022-2025 Roadmap to the Future Grid

NEPOOL Participants Committee Summer Meeting

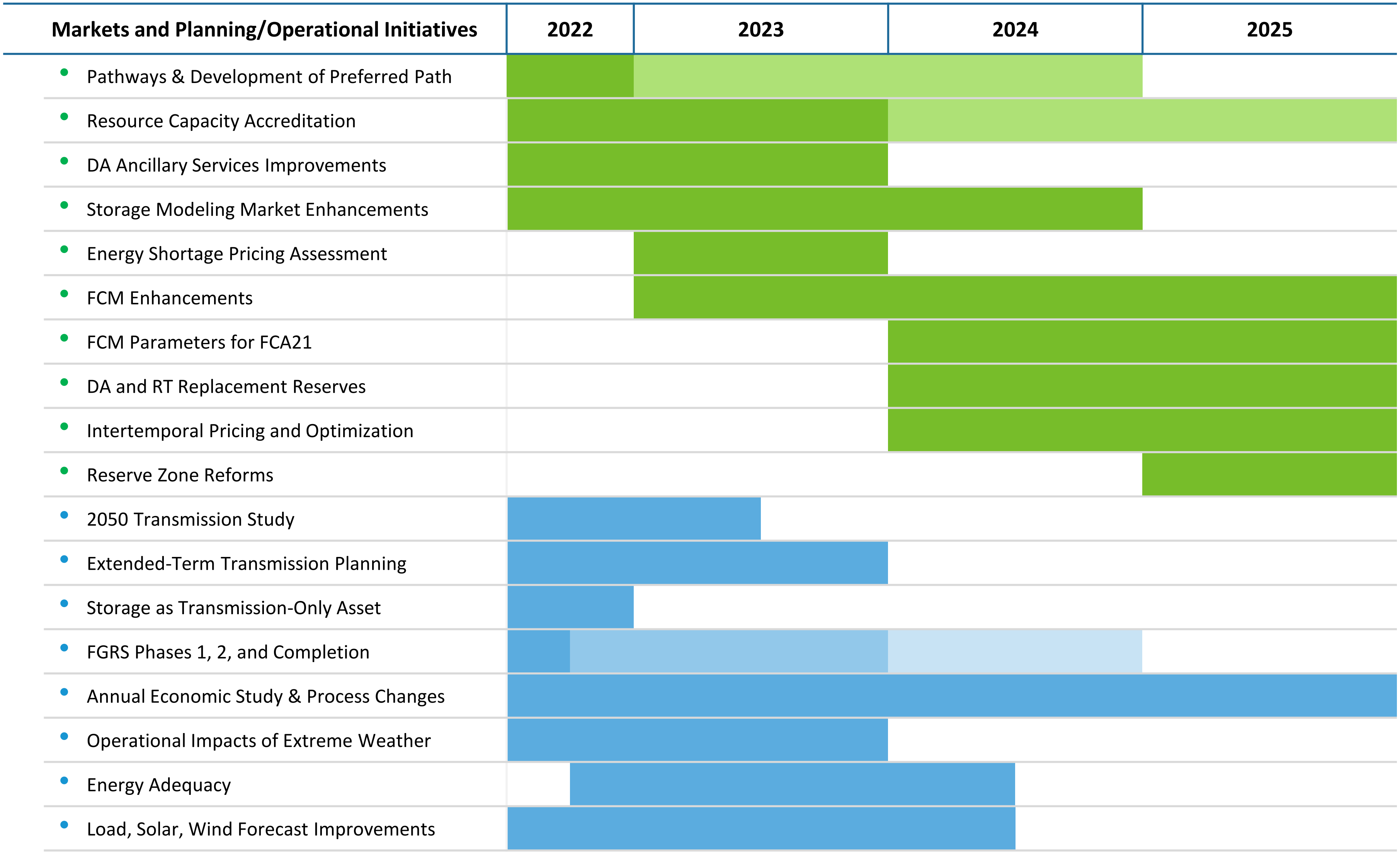
Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

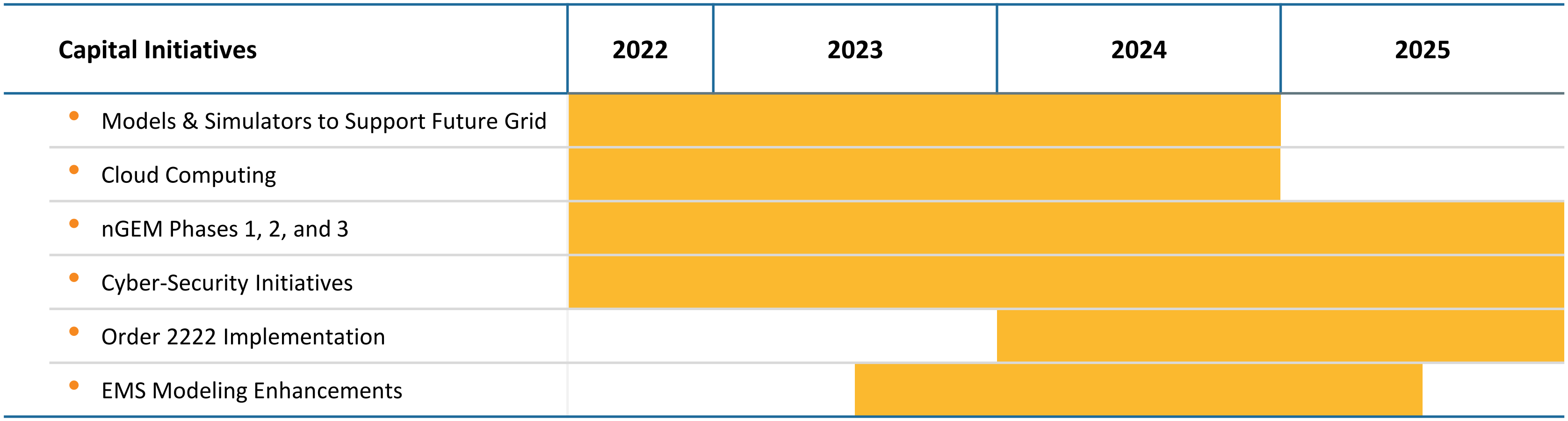
About the 2022-2025 Roadmap

- The following charts show ISO initiatives anticipated to span the next four years that advance the ISO's strategic goals of achieving a reliable, clean-energy transition
  - Includes a number of intensive capital priorities that involve developing technologies foundational to supporting a future system
- The ISO's 2023-2024 budgets are being planned to incorporate the volume of work indicated in this roadmap
- Roadmap does not include:
  - Some smaller projects or projects nearing completion
  - Work representing the ISO's extensive day-to-day operations related to running the grid, markets, IT infrastructure, and its organization
  - Current estimated FERC-mandated or stakeholder-requested work (listed in Appendices)
- Roadmap is snapshot in time; some initiatives in chart may be deferred depending on the scope of Energy Adequacy and Preferred Pathway projects
  - Plans may also adjust over time to reflect emerging requests, regulations, trends, risks
- Timeframes in chart represent ISO work, including assessment, development, and stakeholder processes
  - Lighter shading on chart reflects potential follow-on work (does not indicate implementation work)

2022-2025 Project Roadmap–Current Snapshot



2022-2025 Project Roadmap–Current Snapshot



Summary Descriptions: Market Initiatives

- **Pathways to the Future Grid & Development of Preferred Path –** Solicit feedback on a preferred path(s), confirm the jurisdiction/governance and design, and as necessary develop a detailed design
- **Resource Capacity Accreditation –** New capacity accreditation framework that will more appropriately accredit resource contributions to resource adequacy as the resource mix transforms
- **DA Ancillary Services Improvements –** Appropriately price Day-Ahead Flexible Response Services (10 minute and 30 minute) and Energy Imbalance Reserve products in the market and design market mitigation mechanisms
  - These ancillary service capabilities are needed for a reliable, next-day operating plan with an evolving generation fleet
- **Storage Modeling Market Enhancements –** Consider significant new opportunities to more efficiently integrate fast-responding storage resources into the real-time and day-ahead energy and ancillary service markets (consistent with FERC Order 841 due to be implemented by 2026)
- **Energy Shortage Pricing Assessment–**Evaluate how a load shed event is treated in the energy and ancillary services market pricing software and whether enhancements may be needed to signal appropriate day-ahead and real-time prices in the event of an energy shortage
- **FCM Enhancements –** Portfolio of FCM initiatives, such as Retirement Reforms and other FCM-related initiatives that may stem from assessments

Summary Descriptions: Market Initiatives, cont'd

- **FCM Parameters for FCA 21–** Develop a new set of FCM Parameters, including the choice of "new entry" technology
- **DA and RT Replacement Reserves –** Day-Ahead and Real-Time products to ensure the system has the flexibility and prices to handle uncertain events that may last longer than 30-minute reserve products
  - Example: Sustained and unanticipated multi-hour drop-off in wind production intra-day
- **Intertemporal Pricing and Optimization –** Revise market dispatch and pricing algorithms to better address steep load ramps anticipated with greater solar PV and other renewables (aka, the "duck curve")
  - Benefits reliability by enabling dispatch software to better model variable net load conditions; benefits market efficiency by ensuring the system is more cost-effectively positioned through steep ramps and that costs are transparently signaled though LMPs
- **Reserve Zone Reforms:** Update locational reserve zones to better reflect changes in the New England transmission system in recent years and to accommodate the reliable integration of new clean-energy resources into the system; implement consistent locational reserve zones in the real-time and the new day-ahead co-optimized energy and ancillary service markets to facilitate the day-ahead markets' ability to produce a reliable next-day operating plan

Summary Descriptions: Planning/Operational Initiatives

- **2050 Transmission Study –** Develop a 2050 transmission plan for state-developed scenarios and associated cost estimates
- **Extended-Term Transmission Planning –** Adds Tariff process for approval of public policy-related transmission investments and associated cost allocation
  - Process should permit conversion of the 2050 Transmission study solutions and similar future studies into real projects
- **Storage as Transmission Only Asset –** Develops narrow circumstances in which a storage asset may participate as a transmission-only asset eligible for cost-of-service rates versus participation as market asset
- **Future Grid Reliability Study Phases 1, 2, and Completion –** Studies the future grid from a reliability perspective; extends the study to consider new scenarios and sensitivities, and identifies revenue sufficiency for resources under the various scenarios; and concludes with identifications of gaps and potential approaches to address them
- **Annual Economic Study and Process Changes –** Ongoing effort to study stakeholder-recommended studies from a production-cost modeling perspective that enables insights into system trends as the region transitions to clean energy

Summary Descriptions: Planning/Operational Initiatives, cont'd

- **Operational Impacts of Extreme Weather –** Builds an innovative framework to conduct a probabilistic energy-security study to assess the operational impact of future extreme weather events
- **Energy Adequacy –** Consider a solution to the long-prevalent concerns about energy adequacy during the winter months; the near-term and long-term solution space is dependent on ongoing conversations within the region and with FERC
- **Load, Solar, Wind Forecast Improvements –** Seeks to improve the wind, solar, and load forecasts through a continuous improvement method including more sophisticated forecast models, increasing the number of weather stations

Summary Descriptions: Capital Initiatives

- **Models and Simulators to Support Future Grid –** Develop a suite of models and tools that allows the ISO to simulate market designs and the future grid, including active participation in industry efforts to develop inverter-based models for a more accurate simulation of the power grid
- **Cloud Computing –** Reliably operating a modern system comprised of renewable and storage resources requires the transfer and storing of vast amounts of data. Over the next five years, implement cloud-computing infrastructure to reduce reliance on energy-heavy data centers and enable faster transfer of data than standard computing methods
- **nGEM Phases 1, 2, and 3 –** Replace 20+ year old DA and RT Market software with the next Generation Electricity Management platform (being developed by GE in a consortium with the ISO, MISO, and PJM) that supports a system with a growing number and type of grid assets, new and more complex market features, ever multiplying security threats, and advancing IT technologies
- **Cyber-Security Initiatives –** Portfolio of projects to implement planned initiatives in the 3-year cyber-security plan to address increasingly complex and frequent cyber-security threats plus new attack vectors, including the Beyond Trust, Security Event Monitoring Infrastructure, expansion of the Electronic Security Perimeter, new Security Operations Center, Crowdstrike, etc.

Summary Descriptions: Capital Initiatives, cont'd

- **Order 2222 Implementation –**Implement the FERC Order 2222 filing that integrates distributed energy resources into the wholesale markets
- **EMS Modeling Enhancements** – Implement necessary EMS modeling enhancements, including those necessary to incorporate storage models, distributed energy resources, and ambient and potentially dynamic line ratings

APPENDIX A:
ESTIMATED FERC-MANDATED WORK

Potential issues signaled by FERC to incorporate into ISO work plans that may impact Roadmap to the Future Grid

Summary Descriptions: FERC Mandates

- **AD21-10:** Modernizing Wholesale Electricity Market Design—Requires ISO/RTOs to report on energy and ancillary services markets and changes necessary over the five and 10 year horizons to address concerns about compensation for flexible resources. Could lead to 2023 FERC order directing changes to these markets
- **RM21-17:** Notice of Proposed Rulemaking on Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection—Proposes reforms to exiting transmission planning and cost allocation processes. A final rule is anticipated either by year end or early 2023
- **RM22-2:** Notice of Inquiry on whether the current compensation framework for reactive power capability requires revision. If rulemaking moves forward, it would affect compensation for reactive power service under Schedule 2 of the OATT
- **RM22-14:** Improvements to Generator Interconnection Procedures and Agreements
- **RM22-10:** Transmission Planning Performance Requirements for Extreme Weather
- **RM22-16:** One-Time Informational Reports on Extreme Weather Vulnerability Assessments Climate Change, Extreme Weather, and Electric System Reliability

Summary Descriptions: FERC Mandates

- **AD22-5:** Notice of Inquiry that seeks to examine whether dynamic line ratings are needed to ensure just and reasonable wholesale rates; if rulemaking moves forward, it would likely affect/expand ongoing Order No. 881 compliance effort
- **EL21-94**: Order Establishing Additional Briefing and Instituting Section 206 Proceeding regarding its concerns that Section I.3.10 of the Tariff and the definition of Affected System may be unjust and unreasonable. This proceeding relates to the disputes between NECEC and NextEra regarding the impacts on the Seabrook breaker
- **TBD**—Expecting NOPR on interconnection queue reforms and cost allocation for interconnection-related network upgrades, with a potential final rule in 2023
- **TBD**—Potential NOPR in 2023 on transmission planning cost management and transparency. (Docket No. AD22-8, FERC technical conference scheduled for October 6, 2022)

APPENDIX B:
POTENTIAL NEPOOL ISSUES FOR 2023

Potential items NEPOOL is considering to request for inclusion in the ISO's 2023 Annual Work Plan

Summary Descriptions: Potential NEPOOL 2023 Requests

Market-Based Winter Reliability Program

- Explore and potentially develop a market-based winter reliability program that reflects its cost via a market mechanism (e.g., LMP) so that it is transparent to the marketplace, load suppliers, and can be hedgeable

FCM Entry-Related Improvements

Work with stakeholders to review and adopt and/or develop proposed reforms to establish a better balance of incentives for new entry in the FCM

- **FCM Financial Assurance Reforms** – Review/assess the current FCM Financial Assurance requirements and implement reforms to address identified deficiencies/gaps (such as the ISO adopting CPV proposal or something similar)

- **3-Year Capacity Time Out** – Work with stakeholders to review/evaluate current rules and consider elimination or modification of the 3-year time out rule while continuing to address the queue blocking issues that the time out rule was intended to mitigate

Summary Descriptions: Potential NEPOOL 2023 Requests

FCM Bidding/Exit-Related Issues & Potential Reforms

- **Dynamic Delist Bid Threshold (DDBT) Review/Assessment** – Consider possible revisions to the current formula to add more bandwidth
- **FCM Retirement Reforms** – In addition to Sigma proposal, conduct further review/assessment of the current rules and market monitoring review process relating to retirement of existing units, including treatment of retirement bids and bid modifications, retirement track obligations, and alternative mothball options
- **Further Evaluation/Consideration of Sealed Bid FCA** – Work with stakeholders to review and consider a sealed bid FCA

Summary Descriptions: Potential NEPOOL 2023 Requests

Capacity Resource Performance Mechanisms

- **Pay-For-Performance (PFP) Issues –** Perform follow-on work to PFP Memo. Consider if the Performance Penalty Rate (PPR) is too high, do the stop loss and PPR rate at current levels work against each other and send inappropriate signals during scarcity conditions that lasts longer than an hour, should we revisit the definition of a Capacity Scarcity Condition, is the current construct frustrating retirement signals, and others

- **Consideration of an Additional Performance Mechanism** – Further consider additional performance distinctions among resources holding a Capacity Supply Obligation (separate and distinct from scarcity event hours under PFP)

FCM Planning Horizons

- Review the current three-year forward planning horizon and depending on outcome of assessment, consider potential alternative time horizons

Summary Descriptions: Potential NEPOOL 2023 Requests

Potential Regulation Market Enhancements

- Review, evaluate, and consider implementing a co-optimization of the regulation market, increasing the current caps of the regulation market, how a unit that provides regulation is treated during PFP events, and how NCPC would not cover shortfall if an asset is regulating in an hour with day-ahead schedule, and energy prices in real-time increase over day-ahead

Settlement Item on Reactive Power

- Consider how capacity cost payments should be a capacity type payment and treated more similarly to capacity revenues than energy revenues

Dynamic Line Ratings (DLR)

- Further consider with stakeholders whether DLR requirements would help with some of the congestion issues in the region

Summary Descriptions: Potential NEPOOL 2023 Requests

Transmission Planning-Related Priority

- **Explore Incremental Improvements/Right-Sizing Transmission Projects–**Develop standards or guidelines for right-sizing future transmission projects
- **Transmission Planning Transparency & Oversight of Costs**—Analyze and report on how to ensure highest impact, lowest cost solutions; evaluation of alternatives; oversight of transmission projects for design, scope and cost; how to ensure broadest benefit from transmission solutions; and how to work with states on potential siting-related issues early in the process of evaluating transmission solutions

Summary Descriptions: Potential NEPOOL 2023 Requests

<u>Information/Transparency-Related Requests</u>

- **Overlapping Impact Study Result Transparency** – Publish publicly (with the appropriate CEII approval) overlapping impact test results, in exactly the same way that Feasibility Study and System Impact Study reports are available in the interconnection space
- **Request for Detailed Information on ISO's Overall Plan to Support Clean Energy Transition** – Produce a detailed roadmap of the initiatives it believes will be necessary to achieve a reliable decarbonized grid
- **Environmental Justice** – Detail plans to address the issue of environmental justice

JUNE 21, 2022

ISO New England 2023 and 2024 Preliminary Operating and Capital Budgets

NEPOOL Participants Committee 2022 Summer Meeting

Robert Ludlow

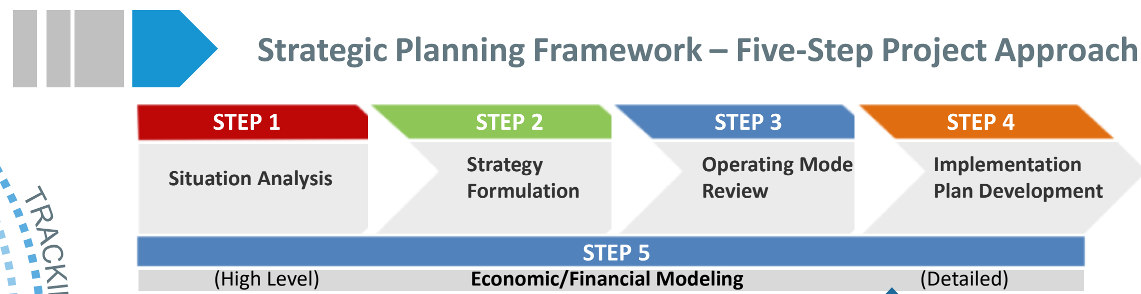
VP, CHIEF FINANCIAL & COMPLIANCE OFFICER

Contents of Presentation

STRATEGIC PLANNING PROCESS OVERVIEW

Strategic Planning Framework

The strategic planning cycle integrates financial planning and metrics with the broader Strategic Goals of the organization in an effort to carry-out the ISO Mission



The budget represents the start of the implementation plan for 2023

Steps 1, 2, & 3, are important to revisit with varied periodicity, for today's discussion the focus is solely on Step 4

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

COORDINATING ISO STRATEGY & BUDGET

ISO New England's Mission and Vision

The vision of the ISO represents our long-term intent and, along with the company's mission, 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

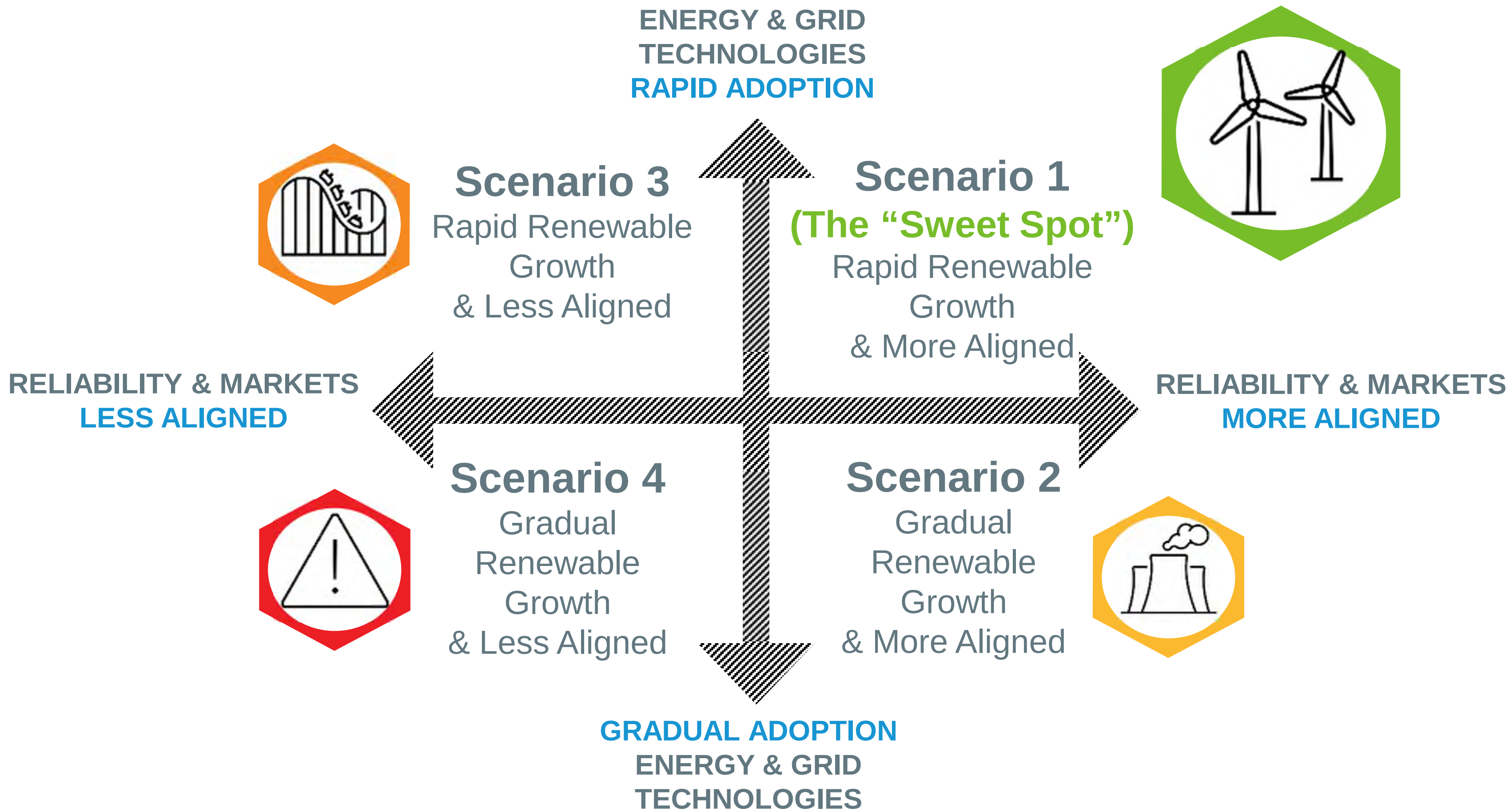
Mission Statement:

Through collaboration and innovation, ISO New England plans the transmission system, administers the region's wholesale markets, and operates the power system to ensure reliable and competitively priced wholesale electricity

The ISO mission statement outlines the core roles and responsibilities of the organization in trying to reach the vision for the future. All work at the ISO is oriented around, and in service of, the mission and vision

Scenario Framework

Scenario planning is a strategic method used for long-range planning, that charts Critical Uncertainties affecting the power industry in New England.



A scenario where all "Four Pillars of the Clean Energy Transition", are robust and solidly support the region's transition to clean energy represents the ideal scenario outcome for the region

The "Four Pillars" of the Clean Energy Transition

In addition to the Strategic Goals, the "Four Pillars" help prioritize work ensuring regional reliability during the transition to clean energy. When the ISO looks toward the future, these are the objectives the ISO, states, market participants, and regulators need to advance in order to support the clean energy transition

Clean Energy Resources (including renewables)

Ensuring sufficient renewable energy generators to harness the sun and wind to produce the carbon-free, but variable, electrical output

Balancing Resources

To produce the balancing electrical output moment-to-moment, and day-to-day. These resources include traditional generation technologies and short-duration batteries, and are largely dependent on the revenues in the wholesale electricity markets

Energy Adequacy

To mitigate disruptions to the energy supply chain to the power system. This includes covering the risk of extended periods of inclement weather and disruptions to the imports of energy to the region

Transmission

To integrate the additional renewable resources and transmit the electrical energy to the distribution system

ISO-NE's Strategic Goals

The strategic goals of the organization are the broad primary outcomes of what the ISO seeks to achieve in order to fulfill the Mission and Vision, and support the "Four Pillars"; the ISO's work-effort is in service of these Strategic Goals

ISO-NE Strategic Goals

- **Responsive Market Designs:** Improve the current market structure and continue to evolve and reposition the market design to reflect 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 reliable 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.

Overview of Preliminary 2023 Objectives

2023 objectives build on and are partially driven by work undertaken in 2022 that will continue into 2023

- 2022 Budget Filing outlined the need for additional FTEs in 2022 and 2023 (14 positions approved in 2022). FTEs will need to significantly increase in 2023 and will support various departments, including in the areas of Market Development, Information and Cyber Security Services, System Planning, Participant Relations & Services, Advanced Technology Solutions, System Operations & Market Admin., External Affairs & Corporate Communications, and Human Resources.
- Some of the expected central initiatives for 2023 are contingent on the outcome of 2022 planned work and FERC Orders, for example:
  - Developing next steps from final Pathways Report
  - Follow-up work for developing ancillary services in 2023 and beyond
  - Improving visibility of Distributed Energy Resources and behind-the-meter resources for modeling, measuring, and forecasting
  - Continuing to strengthen cyber security posture and transition to virtualization and cloud computing
  - Implementing FERC Order regarding MOPR two-year transition; and expected FERC Order 2222 implementation
  - Developing compliance plan for Order 881 directive to use ambient-adjusted ratings as the basis for evaluating near-term transmission service
- *Objectives may change based on emerging state and stakeholder requests; newly developing trends and risks; and FERC Orders and regulations*

Summary of Draft Objectives for 2023

Goal 1: Responsive Market Designs

Better Accommodate Renewable Resource Market Participation

- Continue to review clean energy pricing based on stakeholder engagement
- Commence MOPR elimination
- Implement Solar Do-Not-Exceed

Improve Pricing and Resource Accreditation to Promote Reliability and Manage Resource Uncertainty

- File Resource Capacity Accreditation rules
- Develop design for Day-Ahead Ancillary Service improvements

Summary of Draft Objectives for 2023 *(cont.)*

Goal 2: Progress and Innovation

Developing Advanced Analytics to Address Regional Reliability Risks

- Scoping/Documenting processes for inverter-based resource work
- Next steps for Operational Impacts of Extreme Weather Events project

Enhancing Modeling Capabilities

- Developing tools, processes, and skills to model large quantities of resources entering ISO markets and address the impacts of changing resource mix on operating methodologies
- Developing system capacity, energy, and reliability assessments
- Developing better operational understanding of large-scale offshore wind

Enhanced Understanding of Weather-Effects on Load Forecasting and Behind-the Meter Resources

- Expanding weather forecasting (more granular-level data) and day-ahead forecasting metric improvement
- Enhancing the short-term load forecasts tool (4-hour look-ahead) to take into account real-time weather data

Summary of Draft Objectives for 2023 *(cont.)*

Goal 3: Operational Excellence

Develop Efficiencies in Forecasting and Modeling Practices

- Supporting increased workload of modeling new/smaller/more resources into operating and marketing systems
- Addressing Order 881 (ambient adjusted ratings) and Order 2222 (Distributed Energy Resources)
- Developing capabilities to systematically incorporate the impacts of behind-the-meter resources into demand forecasts and real-time situational awareness tools

Mitigate Organizational Risk Pertaining to Cybersecurity

- Implementing cybersecurity work plans

Improve Operational Business Process Efficiency and Effectiveness

- Managing and updating processes to reflect hybrid workforce
- Supporting advanced capabilities needed for the transition to clean energy
- Developing scalable business efficiencies and processes, including virtualization

Summary of Draft Objectives for 2023 *(cont.)*

Goal 4: Stakeholder Engagement

- Identify preferred Pathway for decarbonization
- Coordinate with Transmission Owners and states on planning for controlled outages
- Collaborate with states on longer-term transmission-planning analyses

Goal 5: Attract, Develop, and Retain Talent

- Support the development of managerial, leadership, interpersonal, and business skills in the context of "post-pandemic" work environment (e.g., hybrid work, changing workforce expectations)
- Use competitive benefits and compensation to attract and retain the technical skills and talent needed to support clean energy transition – upskilling current employees
- Continue to promote the importance of the organization's Mission, Vision, Core Values and Strategic Goals to support retaining and attracting talent
- Ensure ISO's culture is supportive of diversity

2023 AND 2024 PRELIMINARY BUDGET OVERVIEW

2023 and 2024 Preliminary Budget Overview

Key drivers of ISO-NE's projected 2023 and 2024 Operating Budgets

- Working towards the implementation of market mechanisms to reflect the region's effort to transition to high levels of renewable and distributed resources while maintaining a robust fleet of balancing resources.
- Continuing to manage and adapt to the proliferation of new and an increased number of generating resources each of which result in increased complexity for system operations and planning.
- Managing an increasing number of external ad-hoc stakeholder requests and building stakeholder consensus on the prioritization of work.
- Increased funding to support hiring and retention in the tight and competitive labor market, reflecting the difficulty in acquiring and retaining highly skilled employees while remaining competitive within the limitations of the ISO's not-for-profit status.

2023 and 2024 Preliminary Budget Overview *(cont.)*

Key drivers of ISO-NE's projected 2023 and 2024 Operating Budgets *(cont.)*

- Information Technology initiatives, including addressing increasingly complex and frequent cyber security threats; shifting technology to utilize increased levels of cloud infrastructure and virtualization technology in a coordinated manner to improve performance while maintaining IT system reliability; and improving power system modeling capabilities, for both reliability and planning purposes, reflecting the increasing levels of Distributed Energy Resources
- Managing the significant impacts of supply chain and inflationary pressures, including challenges in procuring IT assets and competing for IT staff augmentation consulting support.
- Resourcing to move forward with the goals and priorities of the region, regulators, and market participants while allowing the ISO's to evolve operations, protect the ISO's assets and information, and maintain a highly skilled workforce to carry out the ISO's mission and strategic goals.

2023 and 2024 Preliminary Budget Overview *(cont.)*

Resourcing needs in proposed budgets

- To support the objectives of Four Pillars of the Clean Energy Transition and to continue to maintain its ongoing responsibilities, the ISO anticipates the need for approximately 52 FTE additions between 2023 and 2024 (See Appendix 2 for more details)
- The increased FTEs will better position the ISO to adeptly move forward with the next major challenges facing the region beyond 2024
- The FTE additions are primarily focused in key departments to support the markets and the planning of the transmission system. A small amount of additions are also included in a few back office departments. (See Appendices 1 and 2 for more details)
- Summary of proposed 2023 and 2024 FTE additions by year:

Proposed FTE Additions		
2023*	2024	Total
32	20	52
*For 2023, the proposed budget includes the recruitment of 32 positions with funding for 23 that are expected to onboard throughout the year		

2023 and 2024 Preliminary Budget Overview *(cont.)*

The 2023 budget includes the following:

- The addition of 32 FTEs as noted on slide 19, with funding for approximately 23 positions due to onboarding throughout 2023 (See specific net FTE additions by strategic goal in Appendix 1)
- Other Salary and Benefit related changes including:
  - 5.75% increase for annual merit and promotional increases, including targeted promotional amounts for specific positions or areas (larger increase than prior years to ensure competitive compensation to attract and retain necessary talent to support the ISO's mission and support the transition to clean energy)
  - increases for employee health and dental benefit costs
  - increases for defined contribution plan and post-retirement benefit contributions
  - funding for recruiting, retention, and succession planning
- Professional Fees increases for studies and specialty work; a net increase of three consultant FTEs to augment staff in the areas of Information Technology, Forward Capacity Market Administration, and Finance; and various other increases including inflationary and rate increases across our consulting structure including staff augmentation consulting

2023 and 2024 Preliminary Budget Overview *(cont.)*

The 2023 budget includes the following *(cont.)*:

- Computer Service increases for cyber security product fees and maintenance related to the significant investment made in our cyber infrastructure; for expanded use of virtualization technology; for energy management and market system support; and for inflationary increases across multiple enterprise computer products. Computer Service increases partially offset with savings realized from the replacement of higher cost technology with lower cost products already in use.
- Inflationary increases for other line items, including Insurance Expense, NPCC and NERC Dues, and Interest Expense
- Depreciation Expense increases due primarily to the mid-year go-live of the nGEM Market Clearing Engine Implementation project [1]

(1) Upon completion of the nGEM Market Clearing Engine Implementation, scheduled for June 2023, the following associated Work-In-Progress projects will begin depreciating: CIMNET Simultaneous Feasibility Test with Data Transfer Enhancements, nGEM Value Added Development, nGEM Market Clearing Engine Implementation, nGEM Software Development Parts I and II, and nGEM Hardware Phases I and II.

2023 and 2024 Preliminary Budget Overview *(cont.)*

- 2024 budget assumptions include:
  - The addition of 20 FTEs in the areas of Information Technology, System Planning, Market Development, and Participant Support
  - Merit and Promotional annual increases totaling 4.75%
  - Estimated increases for market or historical trends related to: employee benefits (primarily for health insurance); Computer Services; Insurance Expense; and NPCC/NERC Dues
  - An increase of Interest Expense to fund increases in the Capital Budget program (See Slides 43 - 48)
  - Lower Salary rates due to retirements and employee turnover

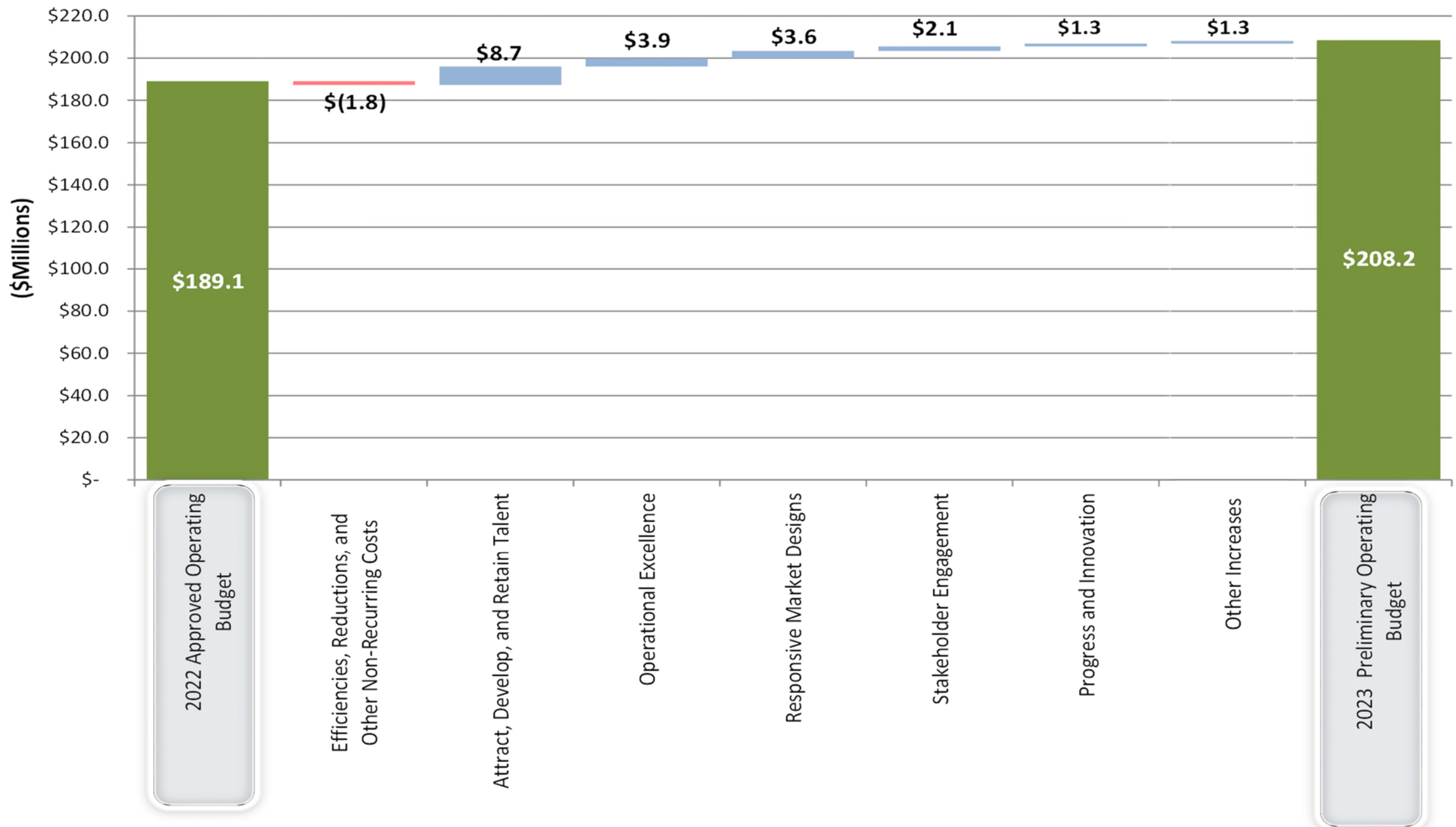
2023 and 2024 Preliminary Budget Overview *(cont.)*

- In summary, the 2023 and 2024 operating budgets' year-over-year increases before depreciation are projected to be $19,115,100 or 10.1% and $13,001,300 or 6.2%, respectively; the projected increases, including depreciation are $24,077,100 or 11.2% and $13,878,800 or 5.8%, respectively
  - The 2023 Revenue Requirement, taking into account the 2021 true-up, is an increase of $8,417,100 or 3.9% over 2022
- The 2023 Capital Budget is also presented in summary form
  - Beginning in 2022 and through at least 2028, the capital budget is expected to increase by up to $7M over the $28M budget that had been in place for several years through 2021
    - The increased capital budget need is being driven by four primary drivers as explained in further detail on Slides 43 - 48
    - 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 2023 Capital Budget is an increase of $1.5 million from the 2022 Capital Budget
  - The 2023 proposed capital budget of $33.5 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 55 - 58)
  - Detailed project descriptions will be presented in August once the final resource requirements are determined

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

2023 Preliminary Budget

Changes in budget by Strategic Goal



Note: The amounts by goal only reflect the increased cost for 2023 when compared to 2022. Additionally, the categories on this slide are in order of magnitude of change, this does not represent the order of importance or priority of the goals. See Appendix 1 for 2023 detailed budget changes by Strategic Goal.

2023 and 2024 Operating Budget Risks

- Significant funding and resource effort may be required for the next phase of the pathways study once a scope of work has been determined
- Additional funding may be required to construct new models to study extreme weather and contingencies; and to conduct new studies related to the integration and penetration of variable resources and emerging technologies, including long-range transmission planning studies
- Information Technology software licensing and maintenance costs, and cloud migration costs may each require additional funding
- Insurance policy renewals may be higher than increases estimated in the budgets
- Mystic Cost of Service audit support may require additional funding
- Interest Rates may impact the ISO 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 the ISO's ability to operate within the approved budget
- Federal and state policy directives/changing policies could result in additional cost associated with new requirements
- Potential impact of workforce sourcing and related pay rates and supply chain disruption impacts

Budget Process – Key Dates

- Review 2023 proposed Operating and Capital Budgets at the August 11th NEPOOL Budget & Finance Subcommittee meeting
- Review 2023 proposed Operating and Capital Budgets at the meeting with State Agencies on August 12th
- Review 2023 proposed Operating and Capital Budgets at the August 18th Audit & Finance Committee meeting
- Review 2023 proposed Operating and Capital Budgets at the September 15th Board Meeting with submitted State Agencies' comments
- NPC vote on the ISO-NE 2023 proposed Budgets at the October 6th meeting
- ISO New England Board of Directors will vote on the 2023 proposed Budgets after the NPC vote
- ISO New England filing of 2023 Budgets with FERC on or about October 14th

APPENDIX 1: 2023 Detailed Budget Changes by Strategic Goal

2023 Preliminary Budget Details

Efficiencies, Reductions, and Other Non-Recurring Costs

Reductions include: ($1.8M)

- Lower salary rates due to employee turnover and retirements
- Lower software licensing costs for replaced technology
- Elimination of cyclical building maintenance from 2022 that isn't recurring in 2023
- Removal of increased Interest Expense, included in 2022 budget, for additional private placement loan borrowings not forecasted to be needed until 2024 based on current cash flow projections
- Reduction in Board of Directors search fees due to only one planned board member retirement in 2023
- A reduction due to the higher allocation of Interest Expense to in-progress capital projects in accordance with accounting guidelines
- A forecasted increase in Interest Income due to expected increase in interest rates

2023 Preliminary Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2023 Initiatives

Goal 5: Attract, Develop, and Retain Talent: $8.7M

- Annual merit and promotional increases by 5.75% ($6.0M)
- Higher estimated cost trend for providing level medical and dental benefits (15% and 5% increases, respectively), defined contribution plan increase, and higher post-retirement medical plan contributions ($1.5M)
- Funding for higher recruiting, retention, and succession planning ($0.9M)
- Funding for 2 Human Resources FTEs for recruiting, benefits, and business partnering ($0.3M)

Note: FTE counts in this Appendix are net funded amount for the 2023 budget which is 23. FTE counts in Appendix 2 are proposed gross additions for 2023 that total 32.

2023 Preliminary Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2023 Initiatives

Goal 3: Operational Excellence: $3.9M

- Computer Services increases for cyber related products including those for security event management, ransomware data recovery, advanced phishing detection, enterprise monitoring software, cloud security software, endpoint security, and threat intelligence ($1.2M)
- Cyber Security consulting for security tools development, continuous improvement efforts, and vendor risk management ($0.4M)
- Increases for additional licensing for virtualizing computing and storage ($0.3M)
- 1.5 FTEs in Information Technology Infrastructure to support network operations, and storage and backup management ($0.3M)
- Addition of 1 FTE in IT Enterprise Application Support to support planned enhancements to suite of applications and planned workflows for several business areas ($0.2M)
- Increases for licensing, fees, and taxes on corporate and control room phone systems, and due to additional market application licensing needs ($0.2M)

Note: FTE counts in this Appendix are net funded amount for the 2023 budget which is 23. FTE counts in Appendix 2 are proposed gross additions for 2023 that total 32.

2023 Preliminary Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2023 Initiatives

Goal 3: Operational Excellence *(cont.)*:

- Finance support for environmental, social, and governance (ESG) reporting; accounting, time entry, and financial reporting system replacement; and additional Accounts Payable support ($0.2M)
- Internal Audit support for data breach response, additional market system algorithm recertification's, and NERC CIP standard compliance ($0.1M)
- Information Technology non-capital purchase of monitors and laptop docking stations in part due to the discontinuation of leasing of these items ($0.1M)
- Other increases primarily inflationary and rate increases for Computer Service products, staff augmentation consultants, and Building Services ($0.9M)

2023 Preliminary Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2023 Initiatives

Goal 1: Responsive Market Designs: $3.6M

- Consulting support for Resource Capacity Accreditation (RCA) ($0.8M)
- 3 FTEs in Market Development to support continued market design and development of RCA, Day-Ahead Ancillary Services, Forward Capacity Market (FCM) evolution and parameters, and the integration of renewable resources in market designs ($0.7M)
- 2 FTEs in Market Development for integration of new resource types including, large scale storage resources including batteries ($0.4M)
- 1.5 FTEs in Resource Qualification to support a new resource category under FERC Order 2222, additional qualification reviews required under the MOPR removal, RCA changes to qualification, and changes to integrate Distributed Energy Resources (DERs) ($0.3M)
- Funding for FCM Net Cost of New Entry changes for FCA 19 and support for managing DERs during qualification phase of FCA 18 ($0.3M)
- Funding for Day-Ahead Ancillary Services review and certification by External Market Monitor ($0.2M)

Note: FTE counts in this Appendix are net funded amount for the 2023 budget which is 23. FTE counts in Appendix 2 are proposed gross additions for 2023 that total 32.

2023 Preliminary Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2023 Initiatives

Goal 1: Responsive Market Designs *(cont.):*

- Energy Management and Market System support due to increased maintenance with the introduction of additional resource types (DERs, solar, wind) ($0.2M)
- 0.5 FTEs each in Advanced Technology Solutions related to the development of market design and in Planning Services due to workload related to RCA and increased use of probabilistic analysis in projects ($0.2M)
- An Operations Training & Integration FTE to support corporate and stakeholder initiative integration, including Day-Ahead Ancillary Services and DERs, into business requirements and tools design, software testing, and process and procedure development ($0.2M)
- An FTE in Market Development to address stakeholder priority issues ($0.2M)
- 0.5 FTE in IT Enterprise Application Development for contributions to Day-Ahead Ancillary Services and RCA efforts and impacted system updates ($0.1M)

Note: FTE counts in this Appendix are net funded amount for the 2023 budget which is 23. FTE counts in Appendix 2 are proposed gross additions for 2023 that total 32.

2023 Preliminary Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2023 Initiatives

Goal 4: Stakeholder Engagement: $2.1M

- Future Grid Reliability Study Part II ($0.5M)
- Long-term transmission studies including further 2050 Transmission Study work ($0.5M)
- 0.5 FTE in Participant Support & Solutions and consulting support to assist in the gathering, managing, and supporting the assessment of participant proposals/requests for the ISO's Annual Work Plan ($0.3M)
- An FTE in External Affairs/Corporate Communications to expand interactions with New England states and the public on ISO initiatives, projects, issue positions, emergency communications, and other related regional efforts ($0.2M)
- Consultant audit support for the Mystic Cost Service agreement ($0.2M)
- Funding for natural gas, solar, and wind dataset updates ($0.2M)
- 0.5 FTE to integrate several new initiatives and projects into market training and to begin development of training delivery methods that reduce the time burden on ISO staff subject matter experts ($0.1M)
- Consultant support to develop and execute a communications plan that broadens our audience to include end-use consumers ($0.1M)

Note: FTE counts in this Appendix are net funded amount for the 2023 budget which is 23. FTE counts in Appendix 2 are proposed gross additions for 2023 that total 32.

2023 Preliminary Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2023 Initiatives

Goal 2: Progress and Innovation: $1.3M

- 1.5 FTEs in Transmission Planning and Transmission Services for NERC standards compliance and to support volume increases in the interconnection queue ($0.3M)
- 2 FTEs in IT for planning model engineering to support the increase of renewables, storage, and DERs in the region ($0.3M)
- 1.5 FTEs in Transmission Planning for long-term transmission planning related to the transition to a carbon free power system and for expected increase in RFPs for Competitive Transmission Solutions ($0.2M)
- 1 FTE in IT for infrastructure cloud engineering support as a result of the current technology shift to cloud resources ($0.2M)
- 0.5 FTE in Advanced Technology Solutions to support advanced modeling and simulation solutions to reflect industry trends such as increasing integration of renewable resources and DERs, uncertain and larger impact of extreme weather events, and transmission network expansion and new transmission technologies ($0.2M)
- Increase in Computer Services for new energy market simulation software and related end user training costs ($0.1M)

Note: FTE counts in this Appendix are net funded amount for the 2023 budget which is 23. FTE counts in Appendix 2 are proposed gross additions for 2023 that total 32.

2023 Preliminary Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2023 Initiatives

Other Increases: $1.3M

- Insurance policy rate increase ($0.5M)
- The allocation of NPCC and NERC dues ($0.4M)
- An increase in Interest Expense due primarily to an increase in tax-exempt debt rates ($0.4M)

APPENDIX 2: BUDGET RESOURCING NEEDS

Summary of Proposed FTE Additions for 2023 and 2024

2023 Budget Resourcing Needs

In 2023 there are a proposed 32 FTE additions as follows:

FTE's	Area / Description	Clean Energy Pillar(s) (*)	Strategic Goal(s)
9.0 FTE's	Market Development		
	For continued market design and development for Resource Capacity Accreditation (RCA), Day Ahead Ancillary Services (DA AS), and Forward Capacity Market (FCM) evolution and parameters; the integration of clean energy resources in market designs, including distributed and storage resources; to address energy adequacy; and to address stakeholder priority issues and FERC orders	**Clean Energy Resources**; **Balancing Resources**	Responsive Market Designs
8.0 FTE's	Information and Cyber Security Services		
	Infrastructure area resources for Network Operations and Cyber Security, information storage and backup management, and cloud engineering; Enterprise Application Support for planned enhancements to suite of applications and workflows for several business areas; and Enterprise Application Development for contributions to RCA and DA AS efforts and impacted system updates	**Clean Energy Resources**; **Balancing Resources**; **Transmission**; Support	Responsive Market Designs; Progress and Innovations; Operational Excellence
5.0 FTE's	System Planning		
	Transmission Planning and Transmission Services for NERC Standards Compliance and to support volume increases in the interconnection queue; for Resource Qualification including a new resource category under FERC Order 2222, additional qualification reviews required under Minimum Offer Price Rule removal, RCA related changes to qualification, and changes to integrate Distributed Energy Resources; and for long-term transmission planning related to the transition to a carbon free power system and for expected increase in RFPs for Competitive Transmission Solutions	**Clean Energy Resources**; **Balancing Resources** **Transmission**	Responsive Market Designs; Progress and Innovations
2.0 FTE's	Participant Relations & Services		
	To integrate several new initiatives and projects into market training and to begin development of training delivery methods that reduce the time burden on ISO staff Subject Matter Experts over time, and to assist in the gathering, managing, and supporting the assessment of participant proposals/requests that the ISO will consider incorporating into our Annual Work Plans	Support	Stakeholder Engagement

(*) See the Four Pillars of the Clean Energy Transition on Slide 9

2023 Budget Resourcing Needs *(cont.)*

In 2023 there are a proposed 32 FTE additions as follows (cont.):

		Clean Energy Pillar(s)	Strategic Goal(s)
2.0 FTE's	Advanced Technology Solutions		
	For solutions related to new market design and increased use of probabilistic analysis in projects, and industry trends such as increasing integration of renewable resources and Distributed Energy Resources; and to address operational impact of extreme events, transmission network expansion, and new transmission technologies that require advanced modeling and simulation solutions	**Clean Energy Resources**; **Balancing Resources**	Responsive Market Designs; Progress and Innovation
2.0 FTE's	System Operations & Market Administration		
	Operations Training & Integration resources to support corporate and stakeholder initiative integration into business requirements and tools design; software testing; and process and procedure development	**Clean Energy Resources**; **Balancing Resources**	Responsive Market Designs
2.0 FTE's	External Affairs & Corporate Communications		
	To expand interactions with New England states and the public on ISO initiatives, projects, issue positions, emergency communications, and other related regional efforts	Support	Stakeholder Engagement
2.0 FTE's	Human Resources		
	Additional support for recruiting, benefits, and business partnering	Support	Attract, Develop, and Retain Talent
32.0	**Total 2023 Proposed FTE Additions**		

For 2023 an additional 23 FTEs are to explicitly address the changing resource mix and support the region's clean energy transition

2024 Budget Resourcing Needs *(cont.)*

In 2024 there are 20 forecasted FTE additions as follows:

FTEs	Description	Clean Energy Pillar(s)	Strategic Goal(s)
9.0 FTE's	**Information and Cyber Security Services**		
	Infrastructure Design Engineer for project design, charter development, project status meetings; Support in Enterprise and Settlements support for ISO priorities related to RCA and DA AS, for additional compliance requirements as we convert to cloud services including multi-factor authentication, for management of continuous integration and delivery for more efficient code development and migrations; Cyber Security support to utilize and maintain new tools that have or are being implemented; and Power System support with continued modeling, nGEM technical support, and support for Market Development efforts	**Clean Energy Resources**; **Balancing Resources** **Transmission**; Support	Responsive Market Designs; Progress and Innovation; Operational Excellence
5.0 FTE's	**System Planning**		
	Resources for continued support of interconnection queue volume including additional cluster studies, for support of RFPs for Competitive Transmission Solutions with changes including multiple proposals providing a solution, support to resume delayed project work (document undocumented Remedial Action Scheme limitations, complete load interruption threshold project, address shortcomings of the probabilistic resource methodology)	**Clean Energy Resources**; **Balancing Resources**	Responsive Market Designs; Stakeholder Engagement
4.0 FTE's	**Market Development**		
	Support for anchor projects such as DA AS including analysis, FRM removal and FCM parameters, distributed and storage resource integration, and support for other developing stakeholder priorities	**Transmission**; Support	Progress and Innovation
2.0 FTE's	**Participant Relations & Services**		
	Resource in Participant Training Services to move beyond maintenance of existing training to convert more in-person training and webinar modules to self-paced micro-learning that provide time and cost savings to the ISO and participant companies, and resource in Project Services to meet process and skill gaps that exist	Support	Stakeholder Engagement
20.0	**Total 2024 Proposed FTE Additions**		

For 2024 an additional 13 FTEs are to explicitly address the changing resource mix and support the region's clean energy transition

APPENDIX 3: 5 YEAR BUDGET COMPARISON

2023 Preliminary Budget – 5 Year Comparison

(Budget Amounts are in Millions)	2023	% Change	2022	% Change	2021	% Change	2020	% Change	2019
Operating Budget Before Depreciation	$208.2	10.1%	$189.1	5.8%	$178.6	1.8%	$175.4	3.9%	$168.9
Capital Budget	33.5	4.7%	32.0	14.3%	28.0	0.0%	28.0	0.0%	28.0
Total Cash Budget	**$241.7**	**9.3%**	**$221.1**	**7.0%**	**$206.6**	**1.6%**	**$203.4**	**3.3%**	**$196.9**
Operating Budget Before Depreciation	$208.2	10.1%	$189.1	5.8%	$178.6	1.8%	$175.4	3.9%	$168.9
Depreciation **(1)**	31.0	19.1%	26.0	(1.2)%	26.3	0.2%	26.3	(9.6)%	29.1
Revenue Requirement Before True-up	239.1	11.2%	215.1	4.9%	205.0	1.6%	201.7	1.9%	198.0
True up	(14.6)		1.1		0.2		(2.9)		(9.3)
Revenue Requirement	**$224.6**	**3.9%**	**$216.1**	**5.4%**	**$205.1**	**3.2%**	**$198.8**	**5.4%**	**$188.7**
Forecast – TWhs (2)	**143.0**	**(1.0)%**	**144.4**	**(2.0)%**	**147.4**	**1.0%**	**145.9**	**0.2%**	**145.6**
$/KWh Rate	**$0.00157**	**4.9%**	**$0.00150**	**7.5%**	**$0.00139**	**2.1%**	**$0.00136**	**5.1%**	**$0.00130**
Average Monthly Consumer Cost (3)	**$1.18**		**$1.12**		**$1.04**		**$1.02**		**$0.97**

(1) The 2023 *preliminary* depreciation budget is a placeholder. The 2023 *proposed* budget will result in a detailed review of project budgets and estimated go-live dates for the impact on depreciation expenses.

(2) 2023 Forecasts based on May 2022 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.

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

Note: Throughout the presentation some schedules may be inconsistent due to rounding.

Appendix 4: Capital Budget Spending 2023-2028

Capital Budget Spending 2023-2028

- The ISO expects the capital budget needs over the next five years will increase by up to $7 million
  - This will increase the ISO annual capital budget incrementally from $28M (2021 budget) to $35M, with $33.5M budgeted for 2023
  - Many of the priorities and projects are similar to last year
- This increase is necessitated by four primary drivers:
  - nGEM platform (which replaces the current market system)
  - Major market and reliability related efforts
  - Cyber security
  - IT asset and infrastructure replacement
- The ISO project expenses are dependent on various external factors, including various vendors and regulatory approvals, and therefore difficult to predict accurately
  - The ISO will continue with its current practice of providing a rolling two-year look-ahead window

Capital Budget Spending 2023-2028 *(cont.)*

nGEM Platform Replacement

- GE proposed the nGEM program (next Generation Markets) to upgrade the core market software, sharing the cost with three ISOs (ISO-NE, PJM, and MISO)
  - The portion of the software upgrade unique to each ISO will be shouldered by each ISO individually
- The GE development and implementation is spread across four phases, and is planned to run through 2027/2028
- Current estimate for the ISO-NE share of the GE platform development cost is approximately $12M across the next five years
- However, the biggest cost for ISO-NE will be in implementing the new platform
  - This will require adapting the base software to unique ISO-NE functionality, testing, market trials with participants, new hardware and data models, and cutover
  - ISO-NE implementation will be in four phases between now and 2027/2028
  - ISO-NE expects the total implementation cost to be approximately $55M - $70M over the next five years

Capital Budget Spending 2023-2028 *(cont.)*

Major Market and Reliability Related Efforts

- Over the next five years, the ISO expects to build the following major market and reliability services, all of which will be complex and expensive efforts
  - Day-Ahead Ancillary Services: The day-ahead ancillary services project will seek to procure and transparently price the ancillary service capabilities needed for a reliable, next-day operating plan with an evolving generation fleet. The ISO plans to develop a day-ahead ancillary services proposal with two components – Energy Imbalance Reserves and Flexible Response Services (10 and 30 minute fast-start and fast-ramping capabilities).
  - FERC Order 2222: The ISO will be building software systems to integrate distributed energy resources into the wholesale market
  - Energy Storage Modeling
  - Various Capacity Market Reforms, including Resource Capacity Accreditation
  - Other Market enhancements as identified through the rolling annual work-plan process and FERC Orders
- Based on scope, these reforms are expected to cost approximately $40M - $55M over the next five years

Capital Budget Spending 2023-2028 *(cont.)*

Cyber Security

- ISO Cyber Security efforts will need to continue to evolve and adapt to emerging threats and new attack vectors
- The ISO expects that it will continue to invest in improved monitoring, detection, and recovery tools to keep pace with increasingly sophisticated attack threats
- This is expected to cost approximately $12M - $15M over the next five years

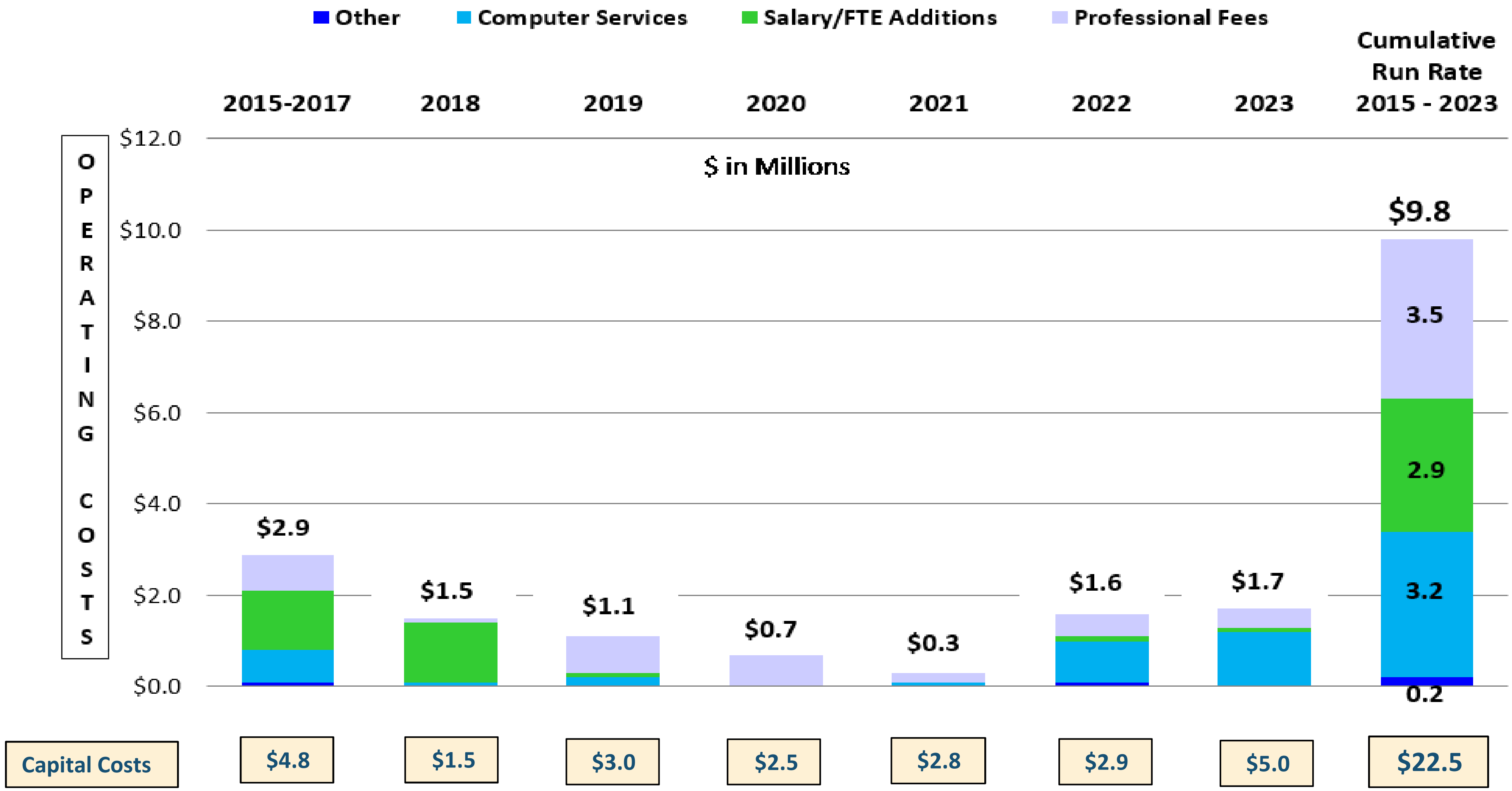
Capital Budget Spending 2023-2028 *(cont.)*

IT Asset and Infrastructure Upgrade

- Current ISO hardware is due for a major upgrade and the ISO has developed a plan to replace major components over the next five years
- The plan also includes developing pilot projects to move a portion of IT services to Amazon Web Services
- This is expected to cost approximately $15M - $20M over the next five years

APPENDIX 5: CYBER SECURITY ANNUAL COSTS 2015-2023

Cyber Security Annual Capital and Incremental Operating Costs 2015-2023

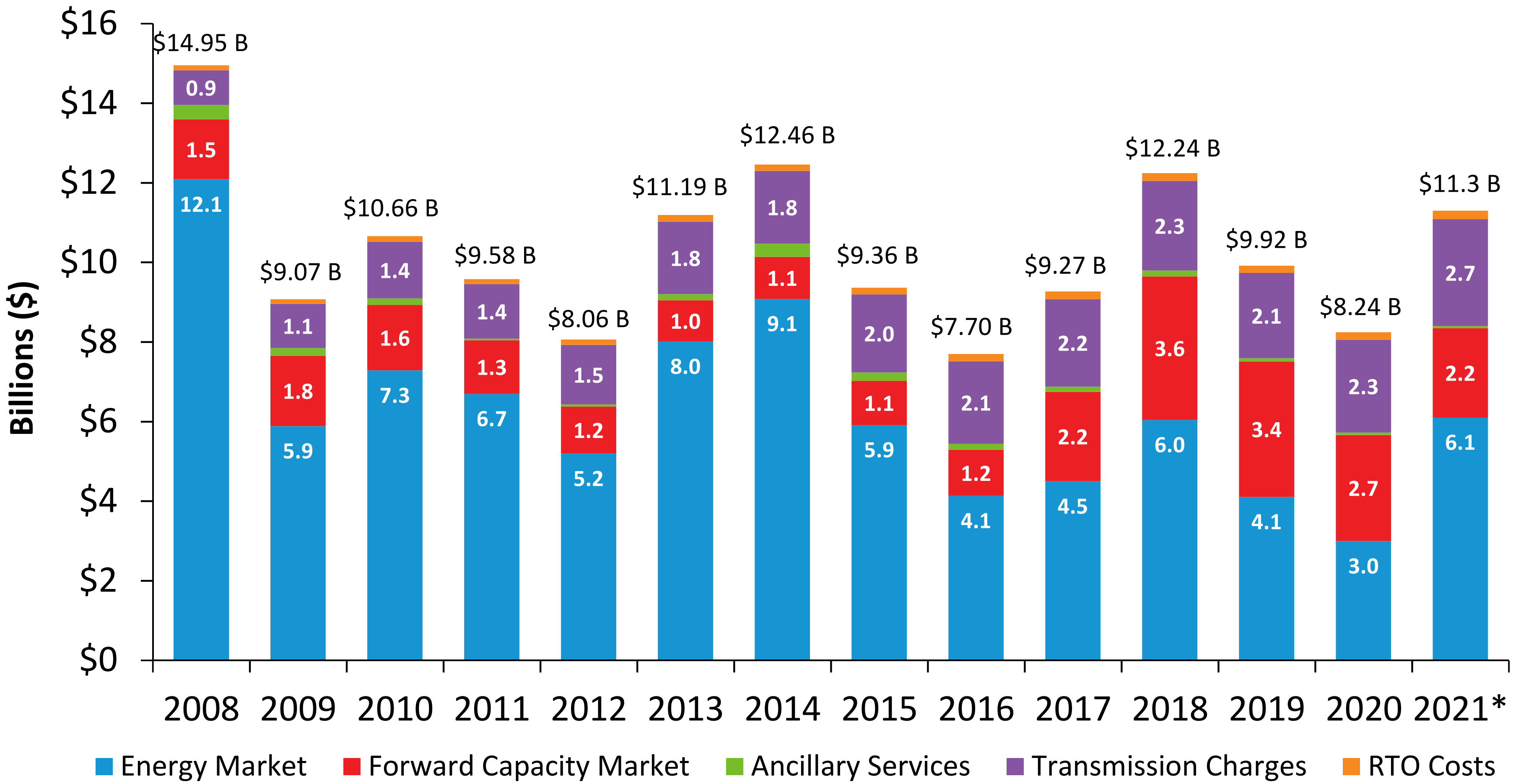


Above amounts represent cumulative annual costs for cyber security that have been added in the 2015 through 2023 budgets and are on-going and included in the 2023 preliminary budget. An additional $1.2 million of incremental non-recurring cyber security costs were incurred from 2015 through 2022 that are not included above.

APPENDIX 6: HISTORICAL NEW ENGLAND WHOLESALE AND RETAIL ENERGY COSTS

New England Wholesale Electricity Costs

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



(The total costs for each year include Ancillary Services and RTO costs)

Source: *2021 Report of the Consumer Liaison Group*; *2021 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]

	2017		2018		2019		2020		2021*	
	$ Mil.	¢/kWh	$ Mil.	¢/kWh	$ Mil.	¢/kWh	$ Mil.	¢/kWh	$ Mil.	¢/kWh
Wholesale Market Costs										
Energy (LMPs)[b]	$4,498	3.5	$6,041	4.7	$4,105	3.3	$2,996	2.4	$6,101	4.8
Ancillaries[c]	$132	0.1	$147	0.1	$83	0.1	$62	0.1	$52	0.0
Capacity[d]	$2,245	1.8	$3,606	2.8	$3,401	2.7	$2,662	2.2	$2,243	1.8
Subtotal	*$6,875*	*5.4*	*$9,794*	*7.6*	*$7,589*	*6.0*	$5,720	4.7	$8,396	6.6
Transmission charges[e]	$2,199	1.7	$2,250	1.7	$2,146	1.7	$2,331	1.9	$2,687	2.1
RTO costs[f]	$193	0.2	$196	0.2	$184	0.1	$191	0.2	$216	0.2
Total	**$9,267**	**7.3**	**$12,240**	**9.4**	**$9,918**	**7.9**	**$8,242**	**6.7**	**$11,299**	**8.9**

(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 2021 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.

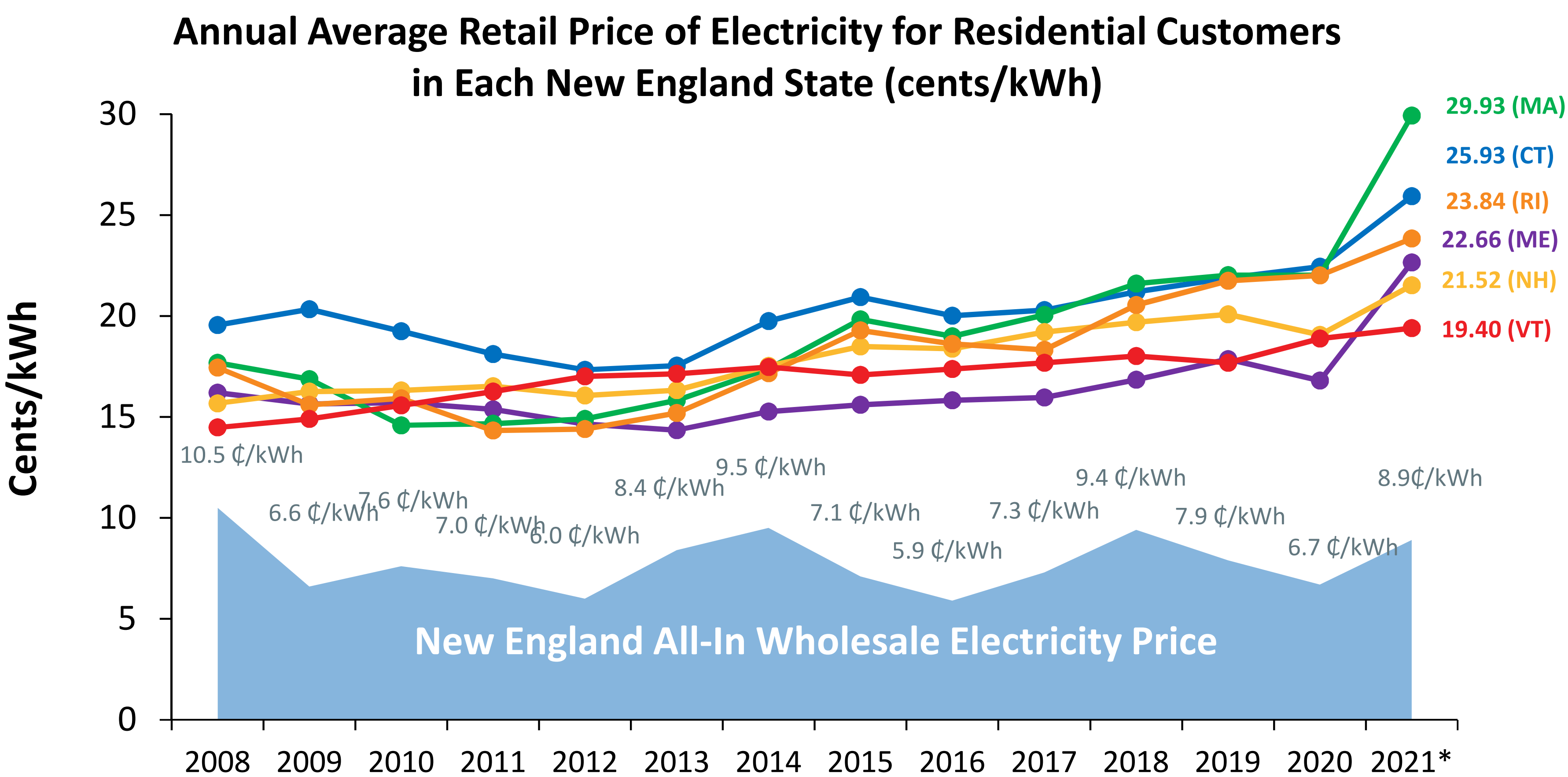
(c) Ancillaries include first- and second-contingency Net Commitment-Period Compensation (NCPC), forward reserves, real-time reserves, regulation service, and a reduction for the Marginal Loss Revenue Fund.

(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); *2021 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)

APPENDIX 7: 2023 Preliminary Capital Budget

Capital Budget
2023 Expenditures

Goal: Responsive Market Designs

Project	2023 Budget	Total Project Cost	Estimated Completion Date	Project Stage
nGEM Market Clearing Engine Implementation (see Note 1)	$1.2M	$13.9M	06/23	In Development
Day-Ahead Ancillary Service Project	$4.0M	$12.3M	12/24	Planning/Conceptual Design
nGEM Real-Time Market Clearing Engine Implem. (see Note 1)	$3.5M	$8.3M	09/24	Planning/Conceptual Design
nGEM Software Development Part II (see Note 1)	$0.4M	$4.8M	03/23	In Development
nGEM Hardware Phase II (see Note 1)	$1.0M	$4.4M	06/23	In Development
Solar Do Not Exceed Dispatch Phase II	$2.0M	$3.0M	12/23	Planning/Conceptual Design
Solar Do Not Exceed Dispatch	$0.4M	$1.6M	12/22	In Development
nGEM Software Development Part III (see Note 1)	$1.5M	$1.5M	12/23	Planning/Conceptual Design
Forward Capacity Market Order 2222	$0.4M	$0.5M	03/23	Planning/Conceptual Design
Total:	**$14.4M**			

Goal: Progress and Innovation

Project	2023 Budget	Total Project Cost	Estimated Completion Date	Project Stage
Forecast Enhancements	$0.4M	$1.8M	07/23	In Development
Control Room Voice Recorder Modernization	$0.6M	$1.0M	03/23	Planning/Conceptual Design
Transition to Cloud	$1.0M	$1.0M	09/23	Planning/Conceptual Design
MIS Reporting by Sub Accounts	$0.1M	$0.5M	03/23	Planning/Conceptual Design
Total:	**$2.1M**			

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.

The 2023 Capital Budget is a preliminary estimate and is still being defined.

Capital Budget

2023 Expenditures *(cont.)*

Goal: Operational Excellence

Project	2023 Budget	Total Project Cost	Estimated Completion Date	Project Stage
Forward Capacity Tracking System Infrastructure Conversion Part III	$0.4M	$3.2M	03/23	In Development
Privileged Access Management Security Enhancements	$1.4M	$2.2M	09/23	Planning/Conceptual Design
Cyber Security Improvements	$1.5M	$1.5M	12/23	Planning/Conceptual Design
2023 Issue Resolution Projects	$1.5M	$1.5M	12/23	Planning/Conceptual Design
Microsoft 365 Service Adoption	$0.5M	$1.5M	12/23	Planning/Conceptual Design
Identity and Access Management Phase III	$1.0M	$1.4M	12/23	Planning/Conceptual Design
Convert Development Computer Room to new Security Ops Center	$0.6M	$1.0M	06/23	Planning/Conceptual Design
Windows Server 2019R2 Deployment	$0.5M	$1.0M	12/23	Planning/Conceptual Design
IT Asset Workflow Integration and Updates	$0.5M	$0.9M	09/23	Planning/Conceptual Design
CIP Electronic Security Perimeter Redesign Phase II	$0.5M	$0.5M	09/23	Planning/Conceptual Design
Non-Project Capital Expenditures	$4.8M			Planning/Conceptual Design
Total:	**$13.2M**			

The 2023 Capital Budget is a preliminary estimate and is still being defined.

Capital Budget

2023 Expenditures Summary

- 2023 Capital Budget Expenditure Summary

Allocation Category		2023 Budget
Goal: Responsive Market Designs		$14.4M
Goal: Progress and Innovation		$ 2.1M
Goal: Operational Excellence		$13.2M
Other Emerging Work		$ 3.0M
Capital Interest		$ 0.8M
	Total:	**$33.5M**

The 2023 Capital Budget is a preliminary estimate and is still being defined.

APPENDIX 8: CAPITAL STRUCTURE

Capital Structure

- The ISO has a $20M working capital line, used to cover the ISO's operational needs; this line currently expires on July 1, 2024

- Tax-Exempt Debt
  – In 2005, the ISO entered into tax-exempt financing in the form of Multi-Mode Variable Rate Civic Facility Revenue Bonds for $45.5M to fund the construction of the Main Control Center in Holyoke, MA
  – In 2012, the ISO entered into a new tax-exempt financing in the form of Multi-Mode Variable Rate Civic Facility Revenue Bonds for $36M to fund a new Backup Control Center
  – The tax-exempt bonds are auctioned weekly and amortize quarterly for 25 years

Capital Structure *(cont.)*

- In November 2013, the ISO entered into an Interest Rate Cap (to mitigate the interest rate risks associated with the tax-exempt debt) for the notional value of $32,215,000, which will expire in 2024 and amortizes as principal payments are made on the tax-exempt debt.
- Capital project costs are largely funded by $50M in Private Placement Notes. The ISO has funded its capital needs with $11M in Private Placement Notes entered into in 2013, and $39M Private Placement Notes in 2014; both series of notes are set to expire in November 2024.
- For the three months ended March 30, 2022, the ISO's total weighted average cost of capital was 2.35%, excluding fees charged on the various debt financing; fees range from .075% to .38%.

Capital Structure *(cont.)*

- Increased Future Capital Funding 2023-2028 and beyond
  - The ISO expects the capital budget needs to increase from the current capital program of $32M to $33.5M in 2023 and to $35M in 2024 and beyond
  - As noted on Capital Budget Spending (See Slides 43-48), the areas driving the increase in spending are dependent on various factors such as vendor and regulatory approvals, estimated range of spending, and longer lead times to complete
  - Longer lead time to complete results in a greater period of time from when ISO spends the capital funds to tariff recovery through depreciation expense of these projects
  - Beyond 2028, the ISO anticipates maintaining the $35M level of capital spending to maintain current infrastructure, continuous improvement in cyber security, and to support the efforts in the markets and reliability

Capital Structure *(cont.)*

- In order to support the future capital program, the ISO anticipates going out to market in 2024 for $75M in Private Placement Notes to replace the $50M set to expire in November 2024
- The banks have indicated to the ISO that pricing will be more advantageous to obtain a higher level of private placement notes, rather than renewing the $50M and securing another form of debt
- The ISO may need to secure an short-term working capital line to support the funding of the capital program in 2023 until the Private Placement Notes are in place
- Once the project charters have been developed, and the budgets are known, the ISO will re-fresh the 5 and 10 year projected cash flows
- The ISO will update the NEPOOL Budget & Finance Subcommittee of the Company's borrowing needs to fund the requisite level of capital spending as part of the regularly scheduled meetings

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of June 17, 2022

The following activity, as more fully described in the attached litigation report, has occurred since the report dated May 3, 2022 ("last Report") was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

I. Complaints/Section 206 Proceedings

	1	RENEW/ACPA Resource Capacity Accreditation & Operating Reserve Designation Complaint (EL22-42)	May 17	ISO-NE answers RENEW Apr 29 answer

II. Rate, ICR, FCA, Cost Recovery Filings

	7	FCA16 Results Filing (ER22-1417)	May 5	Comments filed by: NTE Connecticut, SEIA
			May 16	ISO-NE answers comments
			May 31	No Coal No Gas answers ISO-NE's May 16, 2022 answer
	8	Constellation Post-Spin Updates to Mystic COS Agreement (ER22-1192)	Jun 2	First settlement conference held; second scheduled for ***Jun 28, 2022***
			Jun 3	Constellation moves for adoption of protective order
			Jun 10	Chief Judge adopts protective order
	9	Mystic 8/9 COS Agreement First CapEx Info Filing (ER18-1639)	May 4	Judge Andrea McBarnette designated settlement judge
			May 27	Mystic requests clarification or reh'g of *Mystic First CapEx Info. Filing Order*
			Jun 10	ENECOS answer Mystic's May 27 request
			Jun 15	First settlement conference held

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

	10	MOPR Elimination Filing (ER22-1528)	May 5-20	ISO-NE, NEPOOL, NEPGA, Calpine/Cogentrix/Vistra, and North East Offshore file answers
			May 17	Clean Energy & Consumer Advocates answer ISO-NE, NEPOOL, NEPGA, and Calpine/Cogentrix/Vistra answers
			May 27	FERC accepts MOPR elimination; transition mechanism revisions eff. May 30, 2022; reformed mitigation construct revisions, Mar 1, 2024
	10	New England's *Order 2222* Compliance Filing (ER22-983)	May 16	AEE/PowerOptions/SEIA and AEMA answer ISO-NE and National Grid/Avangrid/Eversource answers
			May 18	FERC issues deficiency letter
			May 24	FERC acknowledges comments by 4 New England US Senators
			Jun 17	ISO-NE files its responses to the May 18 deficiency letter; comments in response to ISO-NE's deficiency letter response due ***Jul 8, 2022***

IV. OATT Amendments / TOAs / Coordination Agreements

*	11	Attachment F Corrections & Updates (ER22-2021)	Jun 3	PTO AC submits proposed revisions to OATT Attachment F to (i) correct minor errors in certain worksheets of the "Formula Rate Template" contained in Appendices A and B; and (ii) update the name of Versant Power in Appendices A, B and D; comment deadline ***Jun 24, 2022***
			Jun 13	NESCOE intervenes

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Changes

*	12	Schedule 21-NEP: Revised RI LSAs Compliance Filing (ER22-1918)	May 20	New England Power submits a compliance filing to (i) reflect all changes to the LSAs accepted by the FERC in ER22-707 and ER22-927 and (ii) provide executed versions of the conformed LSAs
	12	Schedule 21-NEP: 2nd Revised Narragansett LSA (ER22-707)	Jun 16	FERC issues "Allegheny Order", modifying the discussion in the *2nd Rev Narragansett LSA Order* and continuing to reach the same result

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

*	15	Capital Projects Report - 2022 Q1 (ER22-1880)	May 12 May 20-Jun 2 May 20	ISO-NE files 2022 Q1 Report NEPOOL, Eversource intervene NEPOOL files comments
	15	Capital Projects Report - 2021 Q4 (ER22-1041)	Jun 9	FERC accepts 2021 Q4 Report, eff. Jan 1, 2022
*	15	Interconnection Study Metrics Processing Time Exceedance Report Q1 2022 (ER19-1951)	May 16	ISO-NE files required quarterly report
*	16	IMM Quarterly Markets Reports - 2021 Fall (ZZ22-4)	May 4	IMM files Winter 2022 Report; reviewed at May 10 Markets Committee meeting
*	16	IMM 2021 Annual Markets Report (ZZ22-4)	May 26	IMM files annual report covering calendar year 2021
*	17	ISO-NE FERC Form 3-Q (2021/Q4) (not docketed)	May 27	ISO-NE submits its 2021 Q4 FERC Form 3-Q
*	17	ISO-NE 2021 FERC Form 714 (not docketed)	Jun 1	ISO-NE submits its 2021 FERC Form 714

IX. Membership Filings

*	17	Jun 2022 Membership Filing (ER22-1991)	May 31	NEPOOL requests that the FERC accept (i) the memberships of Related Persons Ebsen LLC and Umber LLC (Supplier Sector); (ii) the terminations of Dantzig Energy; Pilot Power Group; and Twin Eagle Resource Management; and (iii) the name change of LS Power Grid Northeast; comment deadline ***Jun 21, 2022***
	18	April 2022 Membership Filing (ER22-1531)	May 26	FERC accepts the memberships of AMP Solar US Holdings, NRG Kiosk and Octopus Energy, eff. Apr 1, 2022
*	18	Suspension Notice – Howard Wind, LLC (not docketed)	Jun 17	ISO-NE files notice of Jun 15 suspension of Howard Wind, LLC from the New England Markets
*	18	Suspension Notice – Manchester Methane, LLC (not docketed)	Jun 6	ISO-NE files notice of Jun 2 suspension of Manchester Methane, LLC from the New England Markets
*	18	Suspension Notice – Pilot Power Group (not docketed)	May 20	ISO-NE files notice of May 18 suspension of Pilot Power Group, LLC from the New England Markets

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

	18	Revised Reliability Standard (CIP-014 Compliance Section) (RD22-3)	Jun 16	FERC approves changes to CIP-014, eff. Jun 16, 2022

	20	Rules of Procedure Changes (CMEP Risk-Based Approach Enhancements) (RR21-10)	May 19	FERC approves in part, and denies in part, NERC's proposed revisions to its Rules of Procedure proposed in NERC's Sep 29, 2021 filing; compliance filing due ***Jul 18, 2022***

XI. Misc. - of Regional Interest

*	21	203 Application: Stonepeak/JERA Americas (EC22-71)	Jun 1	Stonepeak and its Related Person public utilities request authorization for the sale of 100% of their membership interests to a wholly-owned subsidiary of JERA Americas Inc.; comment deadline ***Jun 22, 2022***
			Jun 3-13	MA AG, Public Citizen intervene
	21	203 Application: Pixelle / Spectrum (EC22-49)	May 16	FERC authorizes sale
			May 19	Transaction consummated
			May 25	Spectrum files notice that the transaction was consummated
	21	203 Application: Howard Wind / Greenbacker Wind (EC22-13)	May 3	Transaction consummated
			May 12	Howard Wind files notice that the transaction was consummated
	22	203 Application: PPL/Narragansett (EC21-87)	May 25	Transaction consummated; notice of consummation filed
*	22	IAs: NEP / Narragansett (ER22-2039/2038)	Jun 6	New England Power and Narragansett Electric file wires-to-wires interconnection agreement to govern the interconnection of the two companies' transmission systems; comment deadline ***Jun 27, 2022***
*	22	LGIA: CL&P / EIP Investment (New Britain, CT Fuel Cell) (ER22-1862)	May 12	CL&P files non-conforming LGIA with EIP Investment to govern the interconnection of EIP's 20 MW fuel cell project
	22	Related Facilities Agreement: NSTAR / Ocean State Power (ER22-1675)	Jun 14	FERC accepts RFA, eff. Apr 26, 2022
	22	CL&P Att. F App. D Depreciation Rate Change (ER22-1548)	May 31	FERC accepts rate change, eff. Jul 1, 2022
	23	TSA: NSTAR/Park City Wind (ER22-1247)	Jun 17	FERC accepts TSA, eff. Mar 3, 2022
	24	IA Termination: CL&P / Sterling Property (ER21-2860)	May 10	Eversource answers Sterling's request for clarification and/or rehearing of the *Sterling IA Allegheny Order*
			May 26	FERC issues notice of denial of rehearing of *Sterling IA Allegheny Order* by operation of law
	25	*Orders 864/864-A* (Public Util. Trans. ADIT Rate Changes): New England Compliance Filings (various)	May 6	*ER20-2429 (CMP - LNS).* CMP supplements its further Mar 31 *Order 864* compliance filing
			May 10	*ER22-1850 (UI).* UI submits further compliance filing changes
			Jun 7	*ER20-1089 (New England Elec. Trans. Corp.); ER20-1087 (New England Hydro Trans. Corp.); ER20-1088 (New England Hydro Trans. Elec. Co.); and ER20-2594 (VTransco (1991 VTA)).* FERC accepts filings

XII. Misc. - Administrative & Rulemaking Proceedings

*	26	New England Gas-Electric Winter Forum (AD22-9)	May 19	FERC announces a ***Sep 8, 2022*** forum, to be held in Burlington, VT
	26	NOI: Dynamic Line Ratings (AD22-5)	May 9	PJM files comments
			May 25	AEP, Clean Energy Entities, EEI, Joint Consumer Advocates, MISO TOs, R Street Institute file reply comments

	27	Joint Federal-State Task Force on Electric Transmission (AD21-15)	May 6	FERC convenes third JFSTF meeting
			May 11	FERC issues notice inviting post-meeting comments by Jun 1, 2022
			May 18	Transcript of May 6 meeting posted in eLibrary
			May 23	FERC issues notice of Jul 20, 2022 fourth JFSTF meeting; suggested agenda items due on or before Jun 6, 2022
			Jun 1	Post-May 6 meeting comments filed by: Ameren, EEI, Omaha Power District, Orsted, Xcel Energy
			Jun 6	Suggestions for Jul 20 fourth JFSTF meeting agenda items filed by: ACORE, AEP, Large Public Power Council, NRDC, PJM
	29	Increasing Market and Planning Efficiency Through Improved Software Tech Conf (Jun 21-23, 2022) (AD10-12)	May 27	FERC issues supplemental notice of tech conf; post-tech conf comments due ***Jul 29, 2022***
*	29	NOPR: Extreme Weather Vulnerability Assessments (RM22-16; AD21-13)	Jun 16	FERC issues NOPR proposing to require transmission providers to submit one-time informational reports describing their current or planned policies and processes for conducting extreme weather vulnerability assessments; comment date [60 days after the date of publication in the *Federal Register*]
*	29	NOPR: Interconnection Reforms (RM22-14)	Jun 16	FERC issues NOPR; comment deadline [100 days after the date of publication in the *Federal Register*]; reply comments deadline [130 days after the date of publication in the *Federal Register*]
*	31	NOPR: Transmission System Planning Performance Requirements for Extreme Weather (RM22-10)	Jun 16	FERC issues NOPR; comment deadline [60 days after the date of publication in the *Federal Register*]
	33	*Transmission NOPR* (RM21-17)	May 25	FERC issues notice extending comment date to ***Aug 17, 2022***; reply comments to ***Sep 19, 2022***
			Jun 1, 6	Clean Energy Coalition, Large Public Power Council submit comments
	35	*Order 881-A*: Managing Transmission Line Ratings (RM20-16)	May 19	FERC issues *Order 881-A* addressing arguments raised on rehearing and clarification

XIII. FERC Enforcement Proceedings

39	Rover and ETP (Tuscarawas River HDD Show Cause Order) (IN17-4)	May 11	FERC issues an order dismissing Respondents' request for rehearing of the FERC's Designation Notice
		May 13	Respondents submit surreply to Show Cause Order
40	Total Gas & Power North America, Inc. et al. (IN12-17)	May 9	Interlocutory appeal denied
		May 11	Chief Judge issues order extending the deadline for commencement of hearings to Nov 15, 2022; initial decision deadline to Apr 27, 2023
		May 12	Presiding Judge adopts revised procedural schedule
		Jun 17	Respondents move to dismiss proceedings based on or stay proceedings pending further review of 5th Circuit opinion in *Jarkesy v. Securities Exchange Commission*

XIV. Natural Gas Proceedings

41	Iroquois ExC Project (CP20-48)	Jun 17	Iroquois submits Implementation Plan in accordance with the *Iroquois Certificate Order*
42	Northern Access Project (CP15-115)	May 4	FERC requests additional environmental information
		May 9	National Fuels provides requested information

XV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XVI. Federal Courts

*	44	*2nd Revised Narragansett LSA Orders* (22-1108)	Jun 15	Green Development petitions DC Circuit for review of the FERC's *2nd Revised Narragansett LSA Orders*
			Jun 17	Clerk directs initial submissions and appearances by ***Jul 18, 2022***; dispositive motions, Certified Index to the Record by ***Aug 1, 2022***
	45	NTE CT Petition for Review of Killingly CSO Termination Orders (22-1027)	May 10	DC Circuit dismisses case
	45	CSC Request for Regulatory Asset Recovery of Previously-Incurred CIP IROL Costs (21-1275)	May 17	CSC moves for voluntary dismissal of its petition
			May 31	CSC May 17 motion granted, case dismissed, mandate issued to the FERC
	45	Mystic ROE (21-1198 et al.)	May 4	Court grants CT Parties motion to intervene
			May 24	Court establishes briefing schedule
	46	Mystic 8/9 COS Agreement (20-1343 et al.)(consolidated)	May 5	Oral argument held before Judges Srinivasan, Henderson, Rao
			May 13	FERC moves for leave to issue its *May 2, 2022 Order* (if and to the extent the *May 2, 2022 Order* constitutes a modification or vacatur of the capital structure ruling in the initial orders in this proceeding
			May 23	Parties file responses to FERC's May 13 motion
			Jun 10	Court grants FERC's motion
	48	ISO-NE's Inventoried Energy Program ("IEP") Proposal (19-1224 et al.)	Jun 17	Court issues decision upholding all but one component of the FERC's decision to approve ISO-NE's IEP tariff revisions; vacates the inclusion of nuclear, biomass, coal and hydro generators in the IEP
	49	Algonquin Atlantic Bridge Project Briefing Order (21-1115 et al.)	May 31	Petitioners ask the DC Circuit to continue to hold this proceeding in abeyance

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: June 19, 2022

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 June 17, 2022. If you have questions, please contact us.

I. Complaints/Section 206 Proceedings

- **RENEW/ACPA Resource Capacity Accreditation & Operating Reserve Designation Complaint (EL22-42)**

On March 15, 2022, RENEW Northeast, Inc. ("RENEW") and the American Clean Power Association ("ACPA") filed a Complaint under section 206 of the Federal Power Act ("FPA") against ISO-NE seeking a FERC order directing ISO-NE to make changes to its rules for capacity accreditation and operating reserve designations, effective no later than FCA18 with respect to capacity accreditation and promptly with respect to operating reserve designations. RENEW/ACPA asserted that the changes are needed to address undue preferences granted under ISO-NE's rules and procedures to gas-fired generation resources that have neither dual-fuel capability nor dedicated, firm natural gas supply arrangements ("Gas-Only Resources"). Complainants asserted that the undo preferences arise in the context of capacity accreditation through an assumption of 100% fuel availability for Gas-Only Resources, and in the context of operating reserves, through the absence of any pre-dispatch requirements to confirm fuel availability. ISO-NE's response and comments, following a request for extension granted by the FERC on March 28, were due on or before April 14, 2022.

On April 14, 2022, ISO-NE responded to the Complaint. Protests and comments on the Complaint were filed by: NEPOOL, AEE, Calpine, EDF, FirstLight, LS Power, NEPGA, NESCOE, Public Interest Orgs,[2] Vistra/LSP Power, State Parties,[3] EPSA, National Hydropower Assoc., and the Solar Energy Industries Association ("SEIA"). On April 29, RENEW/ACPA answered the ISO-NE and NEPOOL motions to dismiss and answered the protests and comments filed in opposition to the Complaint. On May 17, ISO-NE answered the April 29 RENEW/ACPA answer. Interventions only were filed by AEP, Avangrid, Avangrid Renewables, Borrego, Brookfield, Constellation, CPV Towantic, Dominion, ENE, Excelerate, National Grid, NextEra, NH OCA, North East Offshore, NRG, Public Systems,[4] CT PURA, MA DPU, MPUC, Repsol, APPA, EPSA, the Institute for Policy Integrity at New York University School of Law, and Public Citizen. This matter is pending before the FERC. If you have any questions concerning this matter,

[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] "Public Interest Orgs" are the Sustainable FERC Project, Acadia Center, Conservation Law Foundation ("CLF"), Sierra Club, and Natural Resources Defense Council ("NRDC").

[3] "State Parties" are the Connecticut Department of Energy and Environmental Protection ("CT DEEP"), the Massachusetts Attorney General ("MA AG"), and the Connecticut Attorney General ("CT AG").

[4] "Public Systems" are Connecticut Municipal Electric Energy Cooperative ("CMEEC"), Massachusetts Municipal Wholesale Electric Company ("MMWEC"), New Hampshire Electric Cooperative, Inc. ("NHEC"), and Vermont Public Power Supply Authority ("VPPSA").

please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **NMISA Complaint Against PTO AC (Reciprocal TOUT Discount) (EL22-31)**

On February 14, 2022, the Northern Maine Intendent System Administrator ("NMISA") filed a complaint against the Participating Transmission Owners Committee ("PTO AC") (who for these purposes hold exclusive Section 205 rights) for failure to consider and implement a reciprocal discount to the Through and Out ("TOUT") charges applied to transactions between the New England and Northern Maine regions ("TOUT Discount"), one which would be identical in substance to the reciprocity between New England and New York. The PTO AC response and comments on this Complaint were due on or before March 7, 2022. In its March 7 response, the PTO AC offered the following explanations as to why it is not in a position to advocate for the TOUT Discount: (i) differences between NYISO and NMISA, including the absence of an interconnection between New England and NMISA; (ii) the TOUT rate is how the TOs recover their costs for point-to-point transactions with neighboring utility systems and other systems not electrically connected, and NMISA is similarly situated to HQ and NBSO, which are also subject to a TOUT Rate; (iii) TOUT Rate does not apply to transactions sinking in New England; and (iv) NMISA's proposal would increase customer rates in New England. On March 16, NMISA answered the PTO AC's response. NEPOOL, Brookfield, Calpine, Eversource, National Grid, NESCOE, and Versant Power submitted doc-less interventions. 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).

- **206 Investigation: ISO-NE Tariff Schedule 25 and Section I.3.10 (EL21-94)**

As previously reported, the FERC instituted on September 7, 2021 a proceeding under FPA Section 206 to consider whether Schedule 25 and Tariff section I.3.10 may be unjust and unreasonable.[5] This proceeding arises out of issues raised in the NECEC Transmission LLC ("NECEC")/Avangrid Complaint Against NextEra/Seabrook (related to the interconnection of the New England Clean Energy Connect transmission project ("NECEC Project")) summarized below (EL21-6). Specifically, the FERC identified a concern that "Schedule 25's definition of Affected Party and Tariff section I.3.10 may be unjust and unreasonable to the extent they may allow generating facilities and their components to be identified as facilities on which adverse impacts must be remedied before an elective transmission upgrade can interconnect to the ISO-NE transmission system, even though generators are not subject to the [FERC]'s open access transmission principles," and could result in upgrades identified on an Affected Party's system without any obligation for the Affected Party to construct the identified upgrades.[6]

Accordingly, the FERC directed ISO-NE to: (1) show cause as to why Schedule 25 and Tariff section I.3.10 remain just and reasonable or (2) explain what changes to Schedule 25 and/or Tariff section I.3.10 it believes would remedy the identified concerns if the FERC were to determine that Schedule 25 and/or Tariff section I.3.10 has become unjust and unreasonable and proceeds to establish a replacement rate. On September 8, 2021, the FERC issued a notice of the proceeding and of the refund effective date, which will be October 13, 2020 (the date the NECEC/Avangrid Complaint Against NextEra/Seabrook was filed). Those interested in participating in this proceeding were required to intervene on or before October 5, 2021.[7] NEPOOL, NESCOE, Brookfield, Calpine, Dominion, Eversource, HQ US, LS Power, MA AG, MMWEC, National Grid, NECEC Transmission, NEPGA, NextEra, NRG, CT DEEP, MA DOER, Pixelle Androscoggin (out-of-time), Vistra (out-of-time), ACPA, EPSA, RENEW, and Public Citizen intervened.

ISO-NE Answer. On November 8, 2021, ISO-NE submitted its answer explaining why Schedule 25 and Tariff section I.3.10 remain just and reasonable. ISO-NE called for the FERC to "assist Affected Parties and

[5] *NECEC Transmission LLC and Avangrid, Inc. v. NextEra Energy Resources, LLC et al. and ISO New England Inc.*, 176 FERC ¶ 61,148 (Sep. 7, 2021) ("*Sep 7 Order*").

[6] *Id.* at P 20.

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

Interconnection Customers in resolving any disputes pertaining to upgrades on Affected Systems—such as the dispute between NECEC Transmission and NextEra Energy Seabrook, LLC in Docket No. EL21-6—as quickly as possible." Interested parties had until January 7, 2022 to address whether ISO-NE's existing Tariff remains just and reasonable and if not, what changes to ISO-NE's Tariff should be implemented as a replacement rate.

Comments. Comments were filed by the January 7, 2022 deadline by NEPOOL, NECEC/Avangrid, NEPGA, NextEra. On January 20 NextEra answered the NECEC/Avangrid comments. On January 28, NECEC answered NextEra's January 20 answer and ISO-NE answered NECEC's Jan 7 comments.

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).

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

As previously reported, NECEC and Avangrid Inc. (together, "Avangrid") filed a complaint (the "Complaint") on October 13, 2020 requesting FERC action "to stop NextEra from unlawfully interfering with the interconnection of the NECEC Project and seeking, among other things, an initial, expedited order that would grant certain relief[8] and direct NextEra to immediately commence engineering, design, planning and procurement activities that are necessary for NextEra to construct the generator owned transmission upgrades during Seabrook Station's Planned 2021 Outage. NextEra submitted an answer to the October 13 Complaint (requesting the FERC dismiss or deny the Complaint) and National Grid filed comments. Doc-less interventions were filed by Dominion, Eversource, Calpine, Exelon, HQ US, MA AG, MMWEC National Grid, NESCOE, NRG, and Public Citizen. Avangrid answered NextEra's answer and NextEra answered Avangrid's November 17 answer ("supplemental answer"), repeating its request that the FERC dismiss or deny the Complaint. Avangrid also answered the supplemental answer.

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

Additional Briefing. On September 7, 2021, the FERC issued an order establishing additional briefing in this proceeding and instituted a broader Section 206 proceeding (*see* EL21-94 above).[9] Initial briefs[10] were due on

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[8] 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.

[9] *NECEC Transmission LLC and Avangrid, Inc. v. NextEra Energy Resources, LLC et al. and ISO New England Inc.*, 176 FERC ¶ 61,148 (Sep. 7, 2021).

[10] The FERC requested additional briefing from the Parties, as well as from ISO-NE, on the following issues: (i) whether or not Seabrook's breaker is properly identified as a part of Seabrook's generating facility; (ii) if Seabrook's breaker is part of Seabrook's generating facility, under what authority, if any, Seabrook may be subject to the upgrade obligations imposed on Affected Parties under the ISO-NE Tariff; (iii) if Seabrook's breaker is part of Seabrook's generating facility, what obligations, if any, Seabrook has under its LGIA with respect to replacement of the breaker and whether or not ISO New England Operating Documents and Applicable Reliability Standards impose an obligation to replace the breaker. If Seabrook's breaker is appropriately classified as a system protection facility, what obligations Seabrook has to replace the breaker. If the Seabrook LGIA obligates Seabrook to act, a description of the scope of Seabrook's obligation under the LGIA; (iv) whether there exists any solution for the interconnection of the NECEC Project that may be implemented without the replacement of Seabrook's breaker; and (v) If replacement of Seabrook's breaker is necessary for the interconnection of the NECEC Project, whether there exists any interim solution for the interconnection of the NECEC Project that would allow energization of the NECEC Project prior to the replacement of Seabrook's breaker.

or before October 7, 2021, and were filed by ISO-NE, Avangrid, NextEra, MA AG, NEPGA/EPSA, MA DOER. Reply briefs were due on or before October 22, 2021, and were filed by Avangrid, NextEra, ISO-NE. Avangrid answered NextEra's November 4 answer, NextEra moved to lodge a letter from a Branch Chief of the Nuclear Regulatory Commission ("NRC"), including an Inspection Report for Seabrook Station for the time period from July 1, 2021 through September 30, 2021 (together, the "NRC Seabrook Report"), to directly refute a central claim of Avangrid (that Seabrook should have already replaced the Generation Breaker at issue in this proceeding), and Avangrid opposed that motion to lodge (asserting that the NRC Seabrook Report is outside the scope of these proceedings and will not assist the FERC in its decision making). With briefing complete, this matter is again 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. NextEra moved to lodge both an August 29, 2021 filing containing an executed Engineering and Procurement Agreement ("E&P Agreement") between Seabrook and NECEC Transmission, LLC ("NECEC") that was filed with the FERC on August 19, 2021 and the NRC Seabrook Report. Avangrid answered that motion, asserting that the NRC Seabrook Report was outside the scope of the proceeding and the motion to lodge should be denied. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

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

  - ***Base ROE Complaint I (EL11-66)***. In the first Base ROE Complaint proceeding, the FERC concluded that the TOs' ROE had become unjust and unreasonable,[11] set the TOs' Base ROE at 10.57% (reduced from 11.14%), capped the TOs' total ROE (Base ROE *plus* transmission incentive adders) at 11.74%, and required implementation effective as of October 16, 2014 (the date of *Opinion*

[11] 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*")).

531-A).[12] However, the FERC's orders were challenged, and in *Emera Maine,*[13] the U.S. Court of Appeals for the D.C. Circuit ("DC Circuit") vacated the FERC's prior orders, and remanded the case for further proceedings consistent with its order. The FERC's determinations in *Opinion 531* are thus no longer precedential, though the FERC remains free to re-adopt those determinations on remand as long as it provides a reasoned basis for doing so.

- ***Base ROE Complaints II & III (EL13-33 and EL14-86) (consolidated)***. The second (EL13-33)[14] and third (EL14-86)[15] 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.[16] 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[17] also went to hearing before an ALJ, Judge Glazer, who issued his initial decision on March 27, 2017.[18] 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.[19] 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*.

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[12] *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*").

[13] *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).

[14] 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%.

[15] 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.

[16] *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*").

[17] 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.

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

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

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.[20] 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*[21] (EL14-12; EL15-45) in Section XI below). The FERC established a paper hearing on how its proposed methodology should apply to the four pending ROE proceedings.[22]

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%.[23] 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

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

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

[22] *Id.* at P 19.

[23] *Id.* at P 59.

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[24] 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, Edison Electric Institute ("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, and FERC Trial Staff.

TOs Request to Re-Open Record and file Supplemental Paper Hearing Brief. On December 26, 2019, the TOs filed a Supplemental Brief that addresses the consequences of the November 21 *MISO ROE Order*[25] 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

- **FCA16 Results Filing (ER22-1417)**

As previously reported, ISO-NE filed on March 21, 2022 the results of the sixteenth FCA ("FCA16") held February 7, 2022 for the June 1, 2025-May 31, 2026 Capacity Commitment Period ("CCP"). ISO-NE reported the following highlights:

- FCA16 Capacity Zones were the Southeastern New England ("SENE") Capacity Zone (the Northeastern Massachusetts ("NEMA")/Boston, Southeastern Massachusetts, and Rhode Island Load Zones), the Northern New England ("NNE") Capacity Zone (the Maine, New Hampshire and Vermont Load Zones), the Maine Capacity Zone (the Maine Load Zone) and the Rest-of-Pool ("ROP") Capacity Zone (the Connecticut and Western/Central Massachusetts Load Zones). SENE was modeled as an import-constrained zone; NNE, as an export-constrained Capacity Zone. The Maine Load Zone was modeled as a separate nested export-constrained Capacity Zone within NNE.
- FCA16 commenced with a starting price of $12.40/kW-mo. and concluded for all Capacity Zones after four rounds.
- Capacity Clearing Prices were as follows (prices expressed per kw-mo.): SENE - $2.639; NNE and Maine - $2.531; ROP - $2.591; imports over the NY AC Ties (837 MW) and the Phase I/II HQ Excess external interface (465 MW) - $2.591; imports over Highgate (58 MW) and New Brunswick (144 MW) - $2.531.
- There were no active demand bids for the substitution auction and, accordingly, the substitution auction was not conducted.
- No resources cleared as Conditional Qualified New Generating Capacity Resources.
- No Long Lead Time Generating Facilities secured a Queue Position to participate as a New Generating Capacity Resource.
- No De-List Bids were rejected for reliability reasons.

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

[25] *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).

ISO-NE asked the FERC to accept the FCA16 rates and results, effective July 19, 2022.

Comments on this filing were due on or before May 5, 2022 and were filed by NTE Connecticut (which requested that the FERC note NTE's pending appeal in its order) and SEIA (questioning whether the FCM is producing results that will continue to attract new investment in the types of resources that are required to ensure the reliable delivery of electric power in New England) in addition to comments by over 140 individuals and the No Coal No Gas Campaign, which largely protested the continued selection of Merrimack Station in New Hampshire, and urged a more exigent transition from fossil fuel-fired resources to renewable energy resources. NEPOOL, Calpine, Constellation, Dominion, Eversource, National Grid, NESCOE, and the MA DPU filed doc-less interventions. On May 16, 2022, ISO-NE filed an answer to the comments and protests. No Coal No Gas submitted an answer to ISO-NE's answer on May 31. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Mystic COS Agreement Updates to Reflect Constellation Spin Transaction[26] (ER22-1192)**

On May 2, the FERC accepted and suspended in part Constellation Mystic Power, LLC's ("Mystic's") changes to its Amended and Restated Cost-of-Service Agreement ("COS Agreement") to reflect Mystic's current upstream ownership.[27] The changes were accepted effective as of Jun 1, 2022, but subject to refund. Specifically, the FERC accepted (i) Mystic's changes throughout the COS Agreement to replace the term "Exelon Generation Company, LLC" with "Constellation Energy Generation, LLC"; and (ii) the addition of language to the true-up methodology that provides that the values included in the true-up methodology exclude costs associated with the Spin Transaction. However, noting that Mystic's contested proposal on the issue of capital structure and cost of debt raises issues of material fact that cannot be resolved based on the record, the FERC accepted and suspended this portion of the COS Agreement for a nominal period, to become effective June 1, 2022, subject to refund and to the outcome of paper hearing procedures. The FERC also directed the appointment of a settlement judge and will hold the paper hearing in abeyance so as to provide the participants an opportunity for settlement discussions.[28]

On May 10, Chief Judge Cintron designated Judge Steven Glazer as the Settlement Judge. Judge Glazer convened a first settlement conference on June 2, 2022. A second settlement conference is scheduled for June 28, 2022. Prior to that conference, the parties have agreed to respond to data requests by June 9; attend a technical conference (without Judge Glazer present) on June 15; and provide counter offers (Intervenors on June 17 and Staff on June 21).

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).

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[26] In the Spin Transaction, ExGen's and Mystic's corporate parent changed from Exelon Corporation to a newly-created holding company, Constellation Energy Corporation ("Constellation Corporation"). Mystic continues to be an indirect wholly-owned subsidiary of Constellation Energy Generation, LLC, which in turn is a direct, wholly-owned subsidiary of Constellation Corporation.

[27] *Constellation Mystic Power, LLC*, 179 FERC ¶ 61,081 (May 2, 2022) ("*May 2, 2022 Order*").

[28] *Id.* at P 24.

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

As previously reported, each of the *July 17 Orders*[29] and the *Mystic ROE Orders,*[30] which addressed in part or in whole the COS Agreement[31] among Mystic, Constellation Energy Generation, LLC[32] ("Constellation") and ISO-NE, have been appealed to, and consolidated before, the DC Circuit (*see* Section XVI below).

Revised ROE (Sixth) Compliance Filing (-014). Still pending is Mystic's December 20, 2021 filing in response to the requirements of the *Mystic ROE Allegheny Order*. The sixth compliance filing revised (i) the Cost of Common Equity figures from 9.33% to 9.19%, for both Mystic 8&9 and Everett Marine Terminal ("Everett"), and (ii) the stated Annual Fixed Revenue Requirements for both the 2022/23 and 2023/24 Capacity Commitment Periods. Comments on the sixth compliance filing were due on or before January 10, 2022; none were filed. The Sixth Compliance Filing is pending before the FERC.

First CapEx Info. Filing. On September 15, 2021, Mystic submitted, as required by orders in this proceeding and Sections I.B.1.i. and II.6.of Schedule 3A of the COS Agreement ("Protocols"), its informational filing to provide support for the capital expenditures and related costs that Mystic projects will be collected as an expense between June 1, 2022 to December 31, 2022 ("First CapEx Projects Info. Filing"). Formal challenges to the September 15 filing were submitted by the Eastern New England Customer-Owned Systems ("ENECOS") and NESCOE. Comments on the formal challenges were due on or before November 17, 2021, and Mystic responded on November 17 asserting that that the challenges should be rejected without further procedures. ENECOS and NESCOE replied to Mystic's November 17, 2021 reply on December 2 and December 6, 2021, respectively.

On April 28, 2022, the FERC issued an order granting in part, and denying in part, ENECOS' and NESCOE's formal challenges, subject to refund, and established hearing and settlement judge procedures.[33] The FERC summarily denied NESCOE's challenge regarding the update to the AFRR and ENECOS' challenge with regard to the improper booking of items. Those items, and challenges to other underlying projected costs, may be challenged in connection with Mystic's Second Informational Filing (where the informal challenge process begins on April 1, 2022 and the formal challenge process begins on September 15, 202).[34] The FERC reiterated that all items except return on equity and depreciation are subject to the true-up process described in Schedule 3A of the COS Agreement, not just projected capital expenditures. However, with respect to NESCOE's and ENECOS' allegations that Mystic failed to support all of its projected capital expenditures, the FERC found that the First CapEx Projects

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[29] 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).

[30] *Constellation Mystic Power, LLC,* 176 FERC ¶ 61,019 (July 15, 2021) ("*Mystic ROE Order*") (setting the base ROE for the Mystic COS Agreement at 9.33%); *Constellation Mystic Power, LLC*, 177 FERC ¶ 61,106 (Nov. 18, 2021) ("*Mystic ROE First Allegheny Order*") (re-setting Mystic's ROE to 9.19%); *Constellation Mystic Power, LLC*, 177 FERC ¶ 61,106 (Nov. 18, 2021) ("*Mystic ROE Second Allegheny Order*", and together with the *Mystic ROE Order* and the *Mystic ROE Allegheny Order,* the *"Mystic ROE Orders"*) (modifying the discussion in, but sustaining the results of, the *Mystic ROE First Allegheny Order*).

[31] 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.

[32] On Feb. 1, 2022, Exelon Generation Company, LLC was renamed and is now known as Constellation Energy Generation, LLC.

[33] *Constellation Mystic Power, LLC*, 179 FERC ¶ 61,011 (Apr. 28, 2022) ("*Mystic First CapEx Info. Filing Order*").

[34] *Id.* at PP 23-24.

Info. Filing raised issues of material fact that could not be resolved based on the record and would be more appropriately addressed under hearing and settlement judge procedures.[35] Accordingly, the FERC set these matters for a trial-type evidentiary hearing. The FERC encouraged the parties to make every effort to settle their disputes before hearing procedures are commenced, and to that end, will hold the hearing in abeyance pending the appointment of a settlement judge and completion of settlement judge procedures.[36] On May 4, Chief Judge Cintron designated Judge Andrea McBarnette as the Settlement Judge. A first settlement conference was convened on Wednesday June 15, 2022. Judge McBarnette's first status report (which are to be filed every 60 days) is due on or before ***July 5, 2022***.

Request for Clarification or Rehearing of Mystic First CapEx Info. Filing Order. On May 27, 2022, Mystic requested that the FERC clarify that it did not determine that Mystic's already-litigated historical (pre-2018) rate base is subject to re-litigation as part of any "true-up" process under the Mystic Agreement. ENECOS answered that request on June 10, 2022. Mystic's request is pending before the FERC, with FERC action required on or before June 27, 2022, or the request will be deemed denied by operation of law.

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

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

- **MOPR Elimination Filing (ER22-1528)**

On May 27, 2022, the FERC accepted, without change or condition, ISO-NE's and NEPOOL's proposal to eliminate the FCM Minimum Offer Price Rule ("MOPR") following the implementation of a two-year transition mechanism and to replace it with a reformed buyer-side market power mitigation review construct.[37] The transition mechanism revisions were accepted effective May 30, 2022; the reformed mitigation construct revisions, March 1, 2024, as requested. Each of the Commissioners weighed in apart from the *Order*, with separate concurrences by Chairman Glick, Commissioner Christie, jointly by Commissioners Clements and Phillips, and a dissent by Commissioner Danly. Challenges to the *MOPR Elimination Order* are due on or before ***June 27, 2022***. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **New England's *Order 2222* Compliance Filing (ER22-983)**

On February 2, 2022, ISO-NE, NEPOOL and the PTO AC ("Filing Parties") submitted Tariff revisions ("*Order 2222* Changes") in response to the requirements of *Order 2222*. The Filing Parties stated that the *Order 2222* Changes create a pathway for Distributed Energy Resource Aggregations ("DERAs") to participate in the New England Markets by: creating new, and modifying existing, market participation models for DERA use; establishing eligibility requirements for DERA participation (including size, location, information and data requirements); setting bidding parameters for DERAs; requiring metering and telemetry arrangements for DERAs and individual Distributed Energy Resources ("DERs"); and providing for coordination with distribution utilities and relevant electric retail regulatory authorities ("RERRAs") for DERA/DER registration, operations, and dispute resolution purposes.

Comments, following an extension of time granted by the FERC in response to a request by Advanced Energy Management Alliance ("AEMA"), were due on or before April 1, 2022. NEPOOL filed supplemental comments on March 28. Protests and comments were filed by: AEE/PowerOptions/SEIA; Environmental

[35] *Id.* at P 26.

[36] *Id.* at P 27.

[37] *ISO New England Inc. and New England Power Pool Participants Comm.*, 179 ¶ 61,139 (May 27, 2022) ("*MOPR Elimination Order*").

Organizations;[38] MA AG; Voltus; AEMA and 4 New England US Senators.[39] Doc-less interventions were filed by: Avangrid (CMP/UI), Calpine, Centrica Business Solutions Optimize (out-of-time), Constellation, ENE, Enerwise, Eversource, FirstLight, MA AG, National Grid, NESCOE, NRG, MA DPU, MPUC (out-of-time), APPA, and EEI. ISO-NE (April 20) and National Grid/Avangrid/Eversource (April 19) filed answers to the protests and adverse comments. Since the last Report, AEE/PowerOptions/SEIA and AEMA answered the ISO-NE and National Grid/Avangrid/ Eversource answers.

Deficiency Letter. On May 18, 2022, the FERC issued a 25-page deficiency letter directing ISO-NE to provide, on or before June 17, 2022, additional information and clarifications. ISO-NE filed its 39-page response to the deficiency letter on June 17, 2022. Comments in response to ISO-NE's deficiency letter response are due on or before ***July 8, 2022***.

If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com); Eric Runge (617-345-4735; ekrunge@daypitney.com); or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

IV. OATT Amendments / TOAs / Coordination Agreements

- **Attachment F Corrections & Updates (ER22-2021)**

On June 3, 2022, the PTO AC filed proposed revisions to Attachment F of the OATT to (i) correct minor errors in certain worksheets of the "Formula Rate Template" contained in Appendices A and B; and (ii) update the name of Versant Power in Appendices A, B and D. The PTO AC opined that the proposed corrections and updates do not have any impact on transmission rates and they do not alter the substance of the Formula Rate Template. An effective date of August 2, 2022 was requested. Comments on this filing are due on or before June 24, 2022. Thus far, NESCOE has filed a doc-less intervention. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Order 676-J* Compliance Filing Part I (CSC-Schedule 18-Attachment Z) (ER22-1168)**

On March 2, 2022, in response to the requirements of *Order 676-J*,[40] ISO-NE and Cross-Sound Cable Company ("CSC") filed revisions to ISO-NE Tariff Schedule 18 Attachment Z to incorporate the new cybersecurity and PFV standards contained in the North American Energy Standards Board ("NAESB") Wholesale Electric Quadrant ("WEQ") Version 003.3 Standards ("Schedule 18 Order 676-J Part I Changes").[41] An effective date as of the date of the FERC order accepting these changes was requested. Comments on this filing were due on or before March 23, 2022; none were filed. Doc-less interventions were filed by CSC and NEPOOL. There was no activity since the last Report and this matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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[38] Environmental Organizations are Acadia Center, Conservation Law Foundation ("CLF"), Environmental Defense Fund ("EDF"), Massachusetts Climate Action Network, Natural Resources Defense Council ("NRDC"), Sierra Club, and the Sustainable FERC Project.

[39] Senators Markey (MA), Sanders (VT), Warren (MA), and Whitehouse (RI).

[40] *Standards for Business Practices and Communication Protocols for Public Utilities*, Order No. 676-J, 175 FERC ¶ 61,139 (May 20, 2021) ("*Order 676-J*"). *Order 676-J* revised 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 NAESB's Wholesale Electric Quadrant. 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.

[41] Compliance filings for the rest of the WEQ Version 003.3 Standards (Schedule 24 Order 676-J Part II Changes) were due 12 months after implementation of the WEQ Version 003.2 Standards, or no earlier than Oct. 27, 2022.

- ***Order 676-J* Compliance Filing Part I (TOs-Schedule 20/21-Common) (ER22-1161)**

Also on March 2, 2022, in response to the requirements of *Order 676-J*, the PTO AC, ISO-NE, and the Schedule 20A Service Providers ("S20SPs") (collectively, the "TOs") filed revisions to ISO-NE Tariff Schedules 20A-Common and 21-Common to incorporate the new cybersecurity and PFV standards contained in NAESB WEQ Version 003.3 Standards ("Schedule 20/21-Common Order 676-J Part I Changes").[41] An effective date as of the date the FERC may determine was requested. Comments on this filing are due on or before March 23, 2022; none were filed. Doc-less interventions were filed by NEPOOL and Eversource. There was no activity since the last Report and 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).

- ***Order 676-J* Compliance Filing Part I (ISO-NE-Schedule 24) (ER22-1150)**

Again on March 2, 2022, in response to the requirements of *Order 676-J*, ISO-NE filed revisions to ISO-NE Tariff Schedule 24 (Incorporation by Reference of NAESB Standards) to incorporate the new cybersecurity and PFV standards contained in NAESB WEQ Version 003.3 Standards ("Schedule 24 Order 676-J Part I Changes").[41] An effective date no earlier than June 2, 2022 was requested. The Transmission Committee recommended that the Participants Committee support the Schedule 24 Order 676-J Part I Changes at its March 23 meeting, and the Participants Committee supported the changes at the April 7 meeting (Consent Agenda Item # 1). Comments on this filing were due on or before March 23, 2022; none were filed. NEPOOL, Eversource, MA DPU, and National Grid submitted doc-less interventions. There was no activity since the last Report and 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).

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Changes

- **Schedule 21-NEP: Revised RI LSAs Compliance Filing (ER22-1918)**

On May 20, 2022, New England Power submitted a compliance filing following FERC action on Local Service Agreement ("LSA") filings in ER22-707 (Narragansett LSA) and ER22-927 (BIPCO LSA) to: (i) reflect all changes to the LSAs accepted by the FERC in either docket and (ii) provide executed versions of the conformed LSAs. Comments on the Revised RI LSAs compliance filing were due on or before June 10, 2022; none were filed. This compliance filing is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-NEP: 2nd Revised Narragansett LSA (ER22-707)**

As previously reported, the FERC accepted on February 18, 2022 a LSA among New England Power, The Narragansett Electric Company ("Narragansett") and ISO-NE.[42] As previously reported, the LSA reflects the construction of the new Iron Mine Hill Road Substation and related transmission modifications, and the assessment to Narragansett of a Direct Assignment Facilities Charge ("DAF Charge") associated with the facilities. The Iron Mine Hill Road Substation, a new 115 kV/34.5 kV substation (including modifications necessary to loop Narragansett's existing 115 kV H17 transmission line through the new substation) will connect to a new 34.5 kV distribution feeder, which will serve as the point of interconnection for several distributed generation projects being developed by Green Development, LLC ("Green Development"), located in North Smithfield, Rhode Island. The LSA was accepted effective as of January 1, 2022, as requested. The

[42] *ISO New England Inc. and New England Power Co. d/b/a National Grid*, 178 FERC ¶ 61,115 (Feb. 18, 2022) ("*2nd Rev Narragansett LSA Order*").

FERC was not persuaded by Green Development's arguments that the revised Narragansett LSA was unjust and unreasonable and should be rejected.[43]

Request for Rehearing Denied by Operation of Law. On March 18, 2022, Green Development requested rehearing of the *2nd Rev Narragansett LSA Order.* On April 18, 2022, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[44] The Notice confirmed that the 60-day period during which a petition for review of the *2nd Rev Narragansett LSA Order* could be filed with an appropriate federal court was triggered when the FERC did not act on Green Development's request for rehearing of the *2nd Rev Narragansett LSA 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," (which it did on June 16, *see* immediately below).

2nd Rev Narragansett LSA Allegheny Order. On June 16, 2022, pursuant to section 313(a) of the FPA, the FERC issued an order that modified the discussion, but reached the same result as, in the *2nd Rev Narragansett LSA Order*.[45] On June 15, 2022, Green Development petitioned the DC Circuit for review of the *2nd Rev Narragansett LSA Order* and the *2nd Rev Narragansett LSA Allegheny Order*. Developments in that proceeding will be reported in Section XVI below.

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

- **Schedule 21-VP: 2021 Annual Update Settlement Agreement (ER20-2119-001)**

On March 25, 2022, Versant Power submitted a joint offer of settlement between itself and the MPUC to resolve all issues raised by the MPUC in response to Versant's 2021 annual charges update filed, as previously reported, on June 15, 2021, and as amended on June 20, 2021 and July 8, 2021 (the "Versant 2021 Annual Update Settlement Agreement"). Under Part V of Attachment P-EM to Schedule 21-VP, "Interested Parties shall have the opportunity to conduct discovery seeking any information relevant to implementation of the [Attachment P-EM] Rate Formula. . . ." and follow a dispute resolution procedure set forth there. In accordance with those provisions, the MPUC identified certain disputes with the 2021 Annual Update, all of which are resolved by the Versant 2021 Annual Update Settlement Agreement. Comments on the Versant 2021 Annual Update Settlement Agreement were due on or before April 14, 2022; none were filed. There was no activity since the last Report and this matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

On November 19, 2021, Versant Power submitted a joint offer of settlement between itself and the MPUC to resolve all issues raised by the MPUC in response to Versant's 2020 annual charges update filed, as previously reported, on June 15, 2020 (the "Versant 2020 Annual Update Settlement Agreement"). Under Part V of Attachment P-EM to Schedule 21-VP, "Interested Parties shall have the opportunity to conduct discovery seeking any information relevant to implementation of the [Attachment P-EM] Rate Formula. . . ." and follow a dispute resolution procedure set forth there. In accordance with those provisions, the MPUC identified certain disputes with the 2020 Annual Update, all of which are resolved by the Versant 2020 Annual Update Settlement Agreement. Comments on the Versant 2020 Annual Update Settlement Agreement were due on or before December 9, 2021; reply comments, December 19, 2021; none were filed. There was no

[43] *Id.* at P 55.

[44] *ISO New England Inc. and New England Power Co. d/b/a National Grid*, 179 FERC ¶ 62,035 (Apr. 18, 2022) (notice of denial of rehearing by operation of law and providing for further consideration).

[45] *ISO New England Inc. and New England Power Co. d/b/a National Grid*, 179 FERC ¶ 61,186 (June 16, 2022) ("*2nd Rev Narragansett LSA Allegheny Order*").

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

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

Still pending before the FERC is the MPS Merger Cost Recovery Settlement, filed by Emera Maine on May 8, 2018 to resolve all issues pending before the FERC in the consolidated proceedings set for hearing in the *MPS Merger-Related Costs Order,*[46] and certified by Settlement Judge Dring[47] to the Commission.[48] As previously reported, under this Settlement, permitted cost recovery over a period from June 1, 2018 to May 31, 2021 will be $390,000 under Attachment P of the BHD OATT and $260,000 under the MPD OATT. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

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

Fitchburg Gas & Electric's ("FG&E") 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*[49] *and 531-B*[50] also remains pending. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

[46] *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.

[47] 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.

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

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

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

- ***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 - 2022 Q1 (ER22-1880)**

On May 12, 2022, ISO-NE filed its Capital Projects Report and Unamortized Cost Schedule covering the first quarter ("Q1") of calendar year 2022 (the "Report"). ISO-NE is required to file the Report under section 205 of the FPA pursuant to Section IV.B.6.2 of the Tariff. Report highlights include the following new projects: (i) Packet Broker Infrastructure Replacement Project ($839,600); (ii) Amazon Web Services Cloud Foundation ($829,100); (iii) Integrated Market Simulator Phase II ($495,000); and (iv) FCM Non-Commercial Capacity Trading FA ($290,000). Significant changes for Chartered Projects (2022 budget impact in parentheses) were: (i) FCM Cost Allocation & Accelerated Billing ($185,000 increase); (ii) FCM Tracking System Infrastructure Conversion Part III ($398,200 decrease); (iii) Solar DNE Dispatch Phase I ($386,100 decrease); (iv) nGEM Hardware Phase II ($1.15 million decrease); and (v) TranSMART Technical Architecture Update ($135,500 decrease). Comments on this filing were due on or before June 2, 2022. NEPOOL filed comments on May 20. Eversource did not comment but filed a doc-less intervention. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **Capital Projects Report - 2021 Q4 (ER22-1041)**

On June 9, 2022, the FERC issued an order accepting ISO-NE's February 19, 2022 Capital Projects Report and Unamortized Cost Schedule covering the fourth quarter ("Q4") of calendar year 2021 (the "Report").[51] ISO-NE was 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) nGEM Hardware Phase II ($4.57 million); (ii) Forecast Enhancements ($1.78 million); (iii) Solar Do-Not-Exceed ("DNE") Dispatch Phase I ($1.595 million); (iv) Physical Security Improvement Project ($1.136 million); (v) Replace Messaging Software ($432,100); (vi) Asset Activation Automation ($408,000); (vii) Browser Standardization ($472,000); (viii) Linear State Estimator Phase I ($362,000); (ix) Short-Term Load Forecast Curve Modification Enhancement ($279,600); (x) FCM Delayed Commercial Resource Treatment Phase II ($253,000); and (xi) Energy Management System Communications Monitoring ($235,200). The one significant change for a Chartered Project was the Replacement of the LMP Monitor (an increase of $265,000). Unless the June 9 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **Interconnection Study Metrics Processing Time Exceedance Report Q1 2022 (ER19-1951)**

On May 16, 2022, ISO-NE filed, as required,[52] public and confidential[53] versions of its Interconnection Study Metrics Processing Time Exceedance Report (the "Exceedance Report") for the First Quarter of 2022 ("2022 Q1"). ISO-NE reported that all six of the 2022 Q1 ***Interconnection Feasibility Study ("IFS") reports*** delivered to

[51] *ISO New England Inc.*, Docket No. ER22-1041 (June 9, 2022) (unpublished letter order).

[52] 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.

[53] 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.

Interconnection Customers were delivered later than the best efforts completion timeline.[54] In addition, eight IFS Reports that are not yet completed have exceeded the 90-day completion expectation. The average mean time from ISO-NE's receipt of the executed IFS Agreement to delivery of the completed IFS report to the Interconnection Customer was 176 days (roughly 60 days longer than in 2021 Q4). Four of the six ***System Impact Study ("SIS") reports*** delivered to Interconnection Customers were delivered later than the best efforts completion timeline of 270 days. The average mean time from ISO-NE's receipt of the executed SIS Agreement to delivery of the completed SIS report to the Interconnection Customer was 460 days (an increase of 140 days from 2021 Q4). There were no Interconnection Requests with projects in the Interconnection Facilities Study phase of the interconnection process. Section 4 of the Report identified steps ISO-NE has identified to remedy issues and prevent future delays, including mitigating the impact of backlogs and initiating clustering, moving to earlier in the process certain Interconnection Customer data reviews, and enhanced information sharing and coordination efforts with Interconnecting TOs. This report was not noticed for public comment.

- ***Voltus Petition for a FERC Technical Conference on Order 2222*** **(RM18-9)**

On December 22, 2022, Voltus, Inc. ("Voltus") requested that the FERC convene a technical conference regarding *Order 2222*-related issues sometime in the months of February or March, 2022. Specifically, Voltus requested the technical conference to allow for a collective discussion of key issues arising from the ISO/RTO *Order 2222* compliance proposals, including certain regional variability, roles of industry participants, narrowing perceived knowledge gaps, and subsequent FERC guidance, all of which Voltus asserts supports the request for a technical conference. On January 7, 2022, the FERC issued a notice of Voltus' request, inviting comments on Voltus' request on or before February 7, 2022. Comments supporting Voltus' request were filed by: AEE, AEMA, APPA/NRECA, EEI, ISO-RTO Council, MISO, SPP, Sunrun, Ameren, Camus Energy, Energy Web Foundation, Entegrity Energy Partners, Environmental Law and Policy Center, Fermata LLC, Google, Leapfrog Power, Nuvve Holding, Tesla, U Delaware EV Research and Development Group, and Utilidata. Voltus' request remains pending before the FERC.

- **IMM Quarterly Markets Reports – Winter 2022 (ZZ22-4)**

On May 4, 2022, the IMM filed with the FERC its Winter 2022 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 Winter 2022 Report was discussed with the Markets Committee at the May 10, 2022 Markets Committee meeting.

- **IMM 2021 Annual Markets Report (ZZ22-4)**

On May 26, 2022, the IMM filed its 2021 Annual Markets Report, which covers the 2021 calendar year period.[55] The report addresses the development, operation, and performance of the New England Markets and presents an assessment of each market based on market data, performance criteria, and independent studies, providing the information required under Section 17.2.4 of Appendix A to Market Rule 1. On the basis of its review of market outcomes and related information, the IMM concluded, as it has for many years in a row, that the New England Market operated competitively in 2021. The IMM reported that Day-Ahead and Real-Time Energy prices reflected changes in underlying primary fuel prices, electricity demand and the region's supply mix. No major reliability issues occurred in 2021, and there were no periods in the Energy Market when a shortage of energy and reserves resulted in very high energy prices or reserve scarcity pricing. The IMM reported that gas and energy prices rebounded from the record low levels seen in 2020. Electricity demand increased year-over-year due to colder weather and increased economic activity. The IMM forecasts that weather-normalized demand will begin to increase from 2022 because of the diminishing impacts of energy efficiency and solar generation and the growth in electrification of transportation and heating.

[54] 90 days from the Interconnection Customer's execution of the study agreement.

[55] Please note that Annual Markets Reports filings are not noticed for public comment by the FERC.

Wholesale costs were at their highest level since 2018 and considerably higher than 2020, driven by higher energy costs. For the eighth consecutive year, the forward capacity auction procured surplus capacity. Other highlights included:

- 2021 total wholesale costs ($11.2 billion) were $3.1 billion higher than 2020, driven by higher energy costs; with the exception of capacity costs, each component of the wholesale cost of electricity increased in 2021.
- 2021 Energy costs totaled $6.1 billion, up 97% from 2020 (Day-Ahead LMPs averaged $45.92/MWh; Real-Time LMPs, $44.84/MW).
- Capacity costs ($2.2 billion) decreased 16%. New entry and limited resource retirements have continued to maintain a system surplus of 4-5% above the capacity requirement, applying downward pressure on prices.
- Transmission and reliability costs in 2021 were $2.7 billion, $357 million (15%) more than 2020 costs. The primary driver was a 12% increase in infrastructure improvements costs.

In light of its review, the IMM, in Section 1.6 (pp. 29-33) of the Report, made a number of recommendations for Market Rule changes and identified areas for additional analysis in 2022. These recommendations will be discussed in more detail at the Participants Committee's August 4 meeting.

- **ISO-NE FERC Form 3-Q (2021/Q4) (not docketed)**

On May 27, 2022, ISO-NE submitted its 2021/Q4 FERC Form 3-Q (quarterly financial report of electric utilities, licensees, and natural gas companies). FERC Form 3-Q is a quarterly regulatory requirement which supplements the annual FERC Form 1 financial reporting requirement. These filings are not noticed for comment.

- **ISO-NE 2021 FERC Form 714 (not docketed)**

On June 1, 2022, ISO-NE submitted its Annual Electric Balancing Authority Area and Planning Area Report for calendar year 2021. Through its Form 714 filing, ISO-NE reports, among other things, generation in the New England Control Area, actual and scheduled inter-balancing authority area power transfers, and net energy for load, summer-winter generation peaks and system lambda. The FERC uses the data to obtain a broad picture of interconnected balancing authority area operations including comprehensive information of balancing authority area generation, actual and scheduled inter-balancing authority area power transfers, and load; and to prepare status reports on the electric utility industry including review of inter-balancing authority area bulk power trade information. Planning area data will be used to monitor forecasted demands by electric utility entities with fundamental demand responsibility, and to develop hourly demand characteristics. These filings are not noticed for comment.

IX. Membership Filings

- **June 2022 Membership Filing (ER22-1991)**

On May 31, 2022, NEPOOL requested that the FERC accept (i) the following Applicant's membership in NEPOOL: Ebsen LLC and Umber LLC (both in the Supplier Sector); (ii) the termination of the Participant status of Dantzig Energy; Pilot Power Group; and Twin Eagle Resource Management; and (iii) the name change of LS Power Grid Northeast, LLC (f/k/a New England Energy Connection, LLC). Comments on this filing are due on or before June 21, 2022.

- **May 2022 Membership Filing (ER22-1738)**

On April 29, 2022, NEPOOL requested that the FERC accept (i) the following Applicant's membership in NEPOOL: Altop Energy Trading LLC (Supplier Sector); Indra Power Business CT LLC [Related Person to Palmco Power MA, LLC (Supplier Sector)]; Indra Power Business MA LLC [Related Person to Palmco Power MA, LLC

(Supplier Sector)]; Leicester Street Solar, LLC [Related Person to Agilitas Companies (AR Sector, DG Sub-Sector)]; and Nexamp Markets, LLC [Related Person to Boston Energy Trading and Marketing (Supplier Sector)]; and (ii) the name change of the following Participant: Salem Harbor Power Development LP (f/k/a Footprint Power Salem Harbor Development LP). Comments on this filing were due on or before May20, 2022; none were filed. This matter is pending before the FERC.

- **April 2022 Membership Filing (ER22-1531)**

On May 26, 2022, the FERC accepted the following Applicant's membership in NEPOOL: AMP Solar US Holdings Inc. AR Sector, DG Sub-Sector); NRG Kiosk LLC d/b/a Power Kiosk (Data-Only Member); and Octopus Energy (Supplier Sector).[56] Unless the May 26 order is challenged, this proceeding will be concluded.

- **Suspension Notice (not docketed)**

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

Date of Suspension/ FERC Notice	***Participant Name***	***Default Type***	***Date Reinstated***
May 18/20	Pilot Power Group, LLC	Financial Assurance	N/A
Jun 6/2	Manchester Methane, LLC	Financial Assurance	--
Jun 15/17	Howard Wind, LLC	Payment Default	--

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

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

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

- **Revised Reliability Standard (CIP-014 Compliance Section) (RD22-3)**

On June 16, 2022, the FERC approved proposed changes to the compliance section of CIP-014 (Physical Security).[57] As previously reported, the changes remove from the Compliance section the provision that requires all evidence demonstrating compliance with the standard to be retained at the Transmission Owner's or Transmission Operator's facility. No changes to the mandatory and enforceable provisions of the CIP-014 standard were proposed. The changes were accepted effective as of the date of the order, or June 16, 2022. Unless the June 16 order is challenged, this proceeding will be concluded.

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

As previously reported, NERC is required to file on an informational basis quarterly status updates regarding the development of new or modified Reliability Standards pertaining to virtualization and cloud computing services. On March 15, 2022, NERC submitted an informational filing regarding one active CIP standard development project (Project 2016-02 – Modifications to CIP Standards ("Project 2016-02")).[58] Project 2016-02 focuses on modifications to the CIP Reliability Standards to incorporate applicable protections for virtualized

[56] *New England Power Pool Participants Comm.*, Docket No. ER22-1531 (May 26, 2022) (unpublished letter order).

[57] *N. Am. Elec. Rel. Corp.*, 179 FERC ¶ 61,187 (June 16, 2022).

[58] The other project which had been addressed in prior updates, Project 2019-02, has concluded, and the FERC approved in RD21-6 the Reliability Standards revised as part of that project (CIP-004-7 and CIP-011-3) on Dec. 7, 2021.

environments. A revised schedule for Project 2016-02 calls for final balloting of revised standards in April 2022, NERC Board of Trustees Adoption in May 2022 and filing of the revised standards with the FERC in June 2022.

- **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.[59] On March 25, 2020, Joint Associations[60] 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.

Dec 2021 Informational Filing. In part in response to the comments filed, the FERC, in a December 17, 2020 order,[61] directed NERC to begin a formal process to assess, and to make an informational filing in a little over one year (January 1, 2022) that addresses, the feasibility of voluntarily conducting BES operations in the cloud in a secure manner, as well as the status and schedule for any plans to modify the standards. NERC submitted that informational filing on December 17, 2021. In that filing, NERC addressed the status of NERC's formal process to assess the feasibility of voluntarily conducting BES operations in the cloud in a secure manner, evaluated potential modifications to the CIP Standards to facilitate expanded use of the cloud, and considered topic areas raised in comments to the NOI. NERC requested that the FERC accept the informational filing as consistent with the *Order Directing Info. Filing*. NERC committed to continue to consider ways to support industry in securely adopting evolving technologies as necessary, including conducting BES reliability operating services in the cloud. NERC reported that there is no Standard Authorization Request ("SAR") to initiate standards development or a field test, nor had it identified a reliability gap that would necessitate standards development to facilitate BES reliability operating services in the cloud.

- ***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,[62] 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."[63] 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

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

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

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

[62] *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).

[63] *Order 873* at P 2.

requirement R8, the FERC remanded the retirement of requirements R7 and R8 to NERC for further consideration.[64]

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*[65] (the "MOD A Reliability Standards"). The FERC intends to coordinate the effective dates for the retirement of the MOD A Reliability Standards with successor NAESB business practice standards (v. 003.3) that include Modeling business practices, which were accepted in *Order 676-J*.[66]

- **NPCC Bylaws Changes (RR22-2)**

On March 11, 2022, NERC and NPCC filed for approval changes to the NPCC Bylaws (the "Bylaws") designed to, among other things: (1) to improve corporate governance; (2) to ensure consistency with the Not-for-Profit Corporation Law of the State of New York ("N-PCL"), pursuant to which NPCC is organized; and (3) to remove extraneous provisions rom the Bylaws, create efficiencies, and reflect changes at NPCC since 2012 (when the last changes to the Bylaws were filed). The Bylaws changes are to take effect upon FERC approval. Comments on this filing were due on or before April 1, 2022. Public Citizen protested the filing, arguing that the FERC should require a change to the composition of NPCC's Board of Directors. Specifically, Public Citizen suggested that NPCC be compelled to ensure that, of NPCC's eight board sectors and 15 voting members, "household consumer advocates" have two voting seats in Sector 7 (Sub-Regional Reliability Councils, Customers, Other Regional Entities and Interested Entities), and that regulators, reliability coordinators, and end-users compose at least half of the voting seats of the board. On April 6, 2022, NERC and NPCC jointly responded to the Public Citizen comments. National Grid filed a doc-less intervention. This matter is pending before the FERC.

- **Rules of Procedure Changes (CMEP Risk-Based Approach Enhancements) (RR21-10)**

On May 19, 2022, the FERC approved in part, and denied in part, NERC's proposed revisions to its Rules of Procedure ("ROP") proposed in NERC's September 29, 2021 filing.[67] Specifically, the FERC approved the proposed revisions to the NERC ROP for the Personnel Certification and Credential Maintenance Program in ROP section 600, the Training and Education Program in ROP section 900, and Confidential Information in ROP section 1500. The FERC approved CMEP-related ROP sections 401, 404, 407-409; Appendix 2 (other than the definition of "Self-Logging"); and Appendix 4C sections 5.0, 6.0, 7.0, 8.0, 9.0, and Attachment 1. The FERC rejected certain of the proposed revisions to ROP sections 402, 403, 405, and 406, Appendix 2, and Appendix 4C (concerned that, taken together, those revisions could adversely impact the nature and extent of the ERO's and the FERC's oversight of

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[64] *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.

[65] *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.

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

[67] *N. Am. Elec. Rel. Corp.*, 179 FERC ¶ 61,129 (May 19, 2022). In its Sep. 29, 2021 filing, NERC proposed changes to sections 400 (Compliance Monitoring and Enforcement) and 1500 (Confidential Information), Appendix 2 (Definitions) and Appendix 4C (Compliance Monitoring and Enforcement Program) of NERC's ROP. The changes were proposed to further enhance the risk-based approach to the Compliance Monitoring and Enforcement Program ("CMEP") whereby registered entities and the ERO Enterprise focus on the greatest risks to the reliability and security of the Bulk Power System ("BPS").

reliability compliance and enforcement activities). Accordingly, the FERC directed that NERC submit a 60-day compliance filing (on or before ***July 18, 2022***) reinstating language in its ROP.

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

On August 18, 2021, NERC filed for approval revisions to sections 300 (Reliability Standards Development), Appendix 3B (Procedure for Election of Members of the Standards Committee) and Appendix 3D (Development of Registered Ballot Body Criteria) of the NERC Rules of Procedure ("ROP"), which are designed to update language, staff titles, and processes; remove unnecessary or duplicative obligations; and clarify roles and responsibilities related to the development of Reliability Standards (the "Reliability Standards Development ROP Revisions"). Comments on this filing were due on or before September 8, 2021; none were filed.

Deficiency Letter, Response & Amendment. On February 24, 2022, the FERC issued a deficiency letter, directing NERC to provide, on or before March 28, 2022, additional information and clarifications. On March 18, NERC provided an amended petition for approval, including revisions to Section 305.3.3 (Review of Segment Criteria) to provide that the qualification guidelines and rules for joining Registered Ballot Body Segments shall be reviewed periodically, instead of every three years. Comments on NERC's amended petition were due on or before April 8, 2022. On April 8, 2022, Public Citizen filed comments (relating to "the absence of balanced stakeholder representation in aspects of NERC's governance"). On April 26, 2022, NERC responded to Public Citizen's comments. This matter is pending before the FERC.

XI. Misc. - of Regional Interest

- **203 Application: Stonepeak / JERA Americas (EC22-71)**

On June 1, 2022, Stonepeak[68] requested authorization for the sale of 100% of the interests in Canal Power Holdings LLC to a wholly-owned affiliate of JERA Americas Inc. ("JERA Americas").[69] Comments on the 203 application are due on or before June 22, 2022. Thus far, doc-less interventions have been filed by MA AG and Public Citizen. If you have any questions, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Pixelle / Spectrum (EC22-49)**

On May 16, 2022, the FERC authorized the sale of 100% of the interests in Pixelle Holding[70] by affiliates of the LG Fund to Spectrum Group Buyer, Inc. ("Spectrum").[71] On May 25, Spectrum filed a notice that the transaction was consummated on May 19, 2022. Reporting on this matter is concluded. If you have any questions, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On January 11, 2022, the FERC authorized Greenbacker Wind, LLC's acquisition of 100% of the equity interests in Howard Wind LLC from Everpower Wind Holdings, Inc. ("Everpower").[72] On May 12, 2022 Howard Wind filed a notice that the transaction was consummated on May 3, 2022. Reporting on this matter is concluded. If you have any questions, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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[68] "Stonepeak" includes Canal Power Holdings LLC ("Seller"), and its indirect wholly-owned, public utility subsidiaries, Canal Generating LLC ("Canal Generating"), Canal 3 Generating LLC ("Canal 3"), Bucksport Generation LLC ("Bucksport"), and Stonepeak Kestrel Energy Marketing LLC ("Stonepeak Marketing").

[69] JERA Americas Related Persons include Provisional Member Cricket Valley Energy Center, LLC.

[70] "Pixelle" includes Pixelle Specialty Solutions Holding LLC ("Pixelle Holding") and its indirectly, wholly-owned subsidiaries with FERC-jurisdictional facilities, Pixelle Specialty Solutions LLC, Pixelle Androscoggin LLC, and Pixelle Energy Services LLC (a member of the Generation Sector).

[71] *Pixelle Specialty Solutions Holding LLC et al.*, 179 FERC ¶ 62,091 (May 16, 2022).

[72] *Howard Wind LLC*, 178 FERC ¶ 62,024 (Jan. 11, 2022).

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

On September 23, 2021, the FERC authorized PPL's acquisition of 100% of the outstanding shares of common stock of The Narragansett Electric Company ("Narragansett").[73] On May 25, 2022, Narragansett filed a notice that the transaction was consummated on May 25, 2022. No longer a Related Person of National Grid, Narragansett is now an individual voting member in the Transmission Sector. Reporting on this matter is concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **IAs: NEP / Narragansett (ER22-2039/2038)**

On June 6, 2022, New England Power (ER22-2038) and Narragansett (ER22-2039) each filed a wires-to-wires interconnection agreement ("IA") to govern the interconnection of the two companies' transmission systems. A May 25, 2022 effective date was requested for both of the IA filings. Comments on these IA filings are due on or before June 27, 2022. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **LGIA: CL&P / EIP Investment (New Britain, CT Fuel Cell) (ER22-1862)**

On May 12, 2022, ISO-NE and CL&P filed a non-conforming LGIA with EIP Investment ("EIP") to govern the interconnection of EIP's 20 MW fuel cell project through Interconnection Facilities that include facilities owned and used by The Farmington River Power Company to serve the Stanley Black & Decker manufacturer campus in New Britain, Connecticut. The LGIA is non-conforming in that it contains limited deviations from the *pro forma* LGIA in Schedule 22 of the ISO-NE OATT that are necessary to reflect unique characteristics of the proposed interconnection, including that the Interconnection Facilities include elements that are not for Interconnection Customer's sole use. An April 12, 2022 effective date was requested. Comments on this filing were due on or before June 2, 2022; 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).

- **Related Facilities Agreement: NSTAR / Ocean State Power (ER22-1675)**

On June 14, 2022, the FERC accepted NSTAR's Related Facilities Agreement ("RFA") with Ocean State Power.[74] The RFA provides the terms and conditions governing NSTAR's activities regarding, and Ocean State Power's cost responsibility for, a replacement disconnect switch and associated equipment located at NSTAR's West Walpole Station #447. The RFA was accepted effective as of April 23, 2022, as requested. Unless the June 14 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **CL&P Att. F App. D Depreciation Rate Change (ER22-1548)**

On May 31, 2022, the FERC accepted CL&P's proposed changes to the transmission plant depreciation rate for the Norwalk Harbor-Northport underground transmission line set forth in CL&P's Appendix D to Attachment F of the ISO-NE OATT.[75] CL&P stated that the depreciation rate will reduce CL&P's revenue requirement by approximately $215,199 annually. The changes were accepted effective July 1, 2022, as proposed. Unless the May 31 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).

- **Maine Power Link Application for Negotiated Rate Authority (ER22-1290)**

On March 10, 2022, Maine Power Link, LLC ("MPL") submitted an application for authority to charge negotiated rates associated with transmission capacity rights on its proposed Northern Maine Line transmission

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

[74] *NSTAR Electric Company*, Docket No. ER22-1675 (June 14, 2022) (unpublished letter order).

[75] *ISO New England Inc.*, Docket No. ER22-1548 (May 31, 2022) (unpublished letter order).

project (the "Project").[76] Comments on MPL's application were due on or before March 28, 2022. The Maine Office of Public Advocate ("MOPA") submitted comments urging the FERC to condition its approval of the application subject to a number of additional conditions.[77] On April 15, MPL answered MOPA's comments (asserting that the first two conditions suggested are unnecessary and the other two conditions "can be addressed in the negotiation of the TSA, as part of the Northern Maine RFP process"). On April 19, MOPA answered MPL's April 15 answer. 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).

- **TSA: NSTAR/Park City Wind (ER22-1247)**

On June 17, 2022, the FERC conditionally approved a Transmission Support Agreement ("TSA") that commits NSTAR to construct, and sets forth the Parties' respective responsibilities to finance and pay for, the transmission facilities required to interconnect Park City Wind's proposed 800 MW wind farm off the coast of Martha's Vineyard to NSTAR's transmission system (near West Barnstable on Cape Cod).[78] The question of whether or not some or all of the interconnection costs of this public policy-driven project can be allocated to or regionalized among consumers in other New England states was explicitly left to another day. Of note, Commissioner Christie in his concurrence emphasized that if NSTAR and PCW seek regional cost allocation for any portion of the interconnection costs,

> ISO-NE should ensure that adequate notice and opportunity to be heard is provided to all affected third parties, including the other states in ISO-NE, before making any decision on a request to regionalize such costs, a principle that should apply to any such effort to regionalize the costs of one or more state's public-policy driven projects in any RTO/ISO. Further, imposing the costs of a project driven by one state's public policies onto another state that has not consented to such cost allocation would, in my view, presumably result in unjust and unreasonable rates.[79]

NSTAR was directed to make a compliance filing submitting the TSA in tariff-record format. Challenges, if any, to the *Park City Wind Order* are due on or before July 18. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Versant Power MPD OATT *Order 676-J* Compliance Filing Part I (ER22-1142)**

On March 2, 2022, in response to the requirements of *Order 676-J*, Versant Power filed revisions to Section 4 of the Versant OATT for the Maine Public District ("MPD OATT") to incorporate the new cybersecurity and PFV standards contained in NAESB WEQ Version 003.3 Standards ("Versant MPD OATT Order 676-J Part I Changes").[41] A placeholder effective date was submitted. Comments on this filing were due on or before March 23, 2022; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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[76] The Project, if selected by the Maine Public Utility Commission ("MPUC") in its request for proposals ("RFP") for renewable energy generation and transmission projects ("Northern Maine RFP"), would be a transmission line to connect renewable energy generation projects in northern Maine to the New England transmission system in southern Maine.

[77] The conditions proposed by MOPA included: (i) a demonstration that the MPUC's competitive bidding process will be "sufficiently open, transparent and robust to constrain rates"; (ii) that the rates assessed to the Maine utilities actually reflect the results of the competitive bidding process; (iii) some assurance that the cost of excess capacity on the transmission line is not paid for by Maine customers; and (iv) MPL will bear the full market risk of the project, including the potential for under-recovery of the line's costs if the line is not fully used.

[78] *NSTAR Elec. Co. and Park City Wind LLC*, 179 FERC ¶ 61,200 (June 17, 2022) ("*Park City Wind Order*").

[79] *Id.*, Christie concurrence at P 1.

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

As previously reported, the FERC rejected the notice of termination filed by CL&P of a 2002 Interconnection Agreement ("IA") governing interconnection service to what CL&P characterized as a since-decommissioned 26 MW waste-tire fueled generator located in Sterling, Connecticut (the "Facility").[80] In rejecting the notice, the FERC found that CL&P had "not provided adequate justification demonstrating that the Facility has been decommissioned in order to terminate the Interconnection Agreement."[81] However, the FERC noted that its determination did not indicate that Sterling retains any interconnection rights under the IA, stating that there had been no interconnection rights associated with the facility since ISO-NE deemed the Facility retired in 2017.

Requests for Rehearing and/or Clarification Denied by Operation of Law; Sterling IA Allegheny Order. On January 10, 2022, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[82] The Notice confirmed that the 60-day period during which a petition for review of the *Sterling IA Order* can be filed with an appropriate federal court was triggered when the FERC did not act on CL&P's and Brookfield's requests for rehearing of the *Sterling IA Order*.[83] 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 March 24, 2022, the FERC issued that order, modifying the discussion in the *Sterling IA Order* and continuing to reach the same result.[84]

Request for Clarification and/or Reh'g of Sterling IA Allegheny Order. On April 25, 2022, Sterling requested clarification and/or rehearing of the *Sterling IA Allegheny Order*. On May 10, 2022, Eversource answered Sterling's request for clarification and/or rehearing of *the Sterling IA Allegheny Order*. On May 26, the FERC issued a "Notice of Denial of Rehearing by Operation of Law" on Sterling's April 25 request.[85] Absent an appeal to a federal court which then results in direction to the FERC on further action in this matter, this proceeding is concluded. If you have any questions, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On March 7, 2022, the FERC conditionally accepted Versant Power's 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*, including waiver of certain of those standards that are not applicable to MPD and/or the MPD OATT.[86] In accepting the filing, the FERC directed Versant to revise the MPD OATT to include a citation to the FEC order originally granting the waiver requests to be continued by the *Versant Order 676-I Compliance Filing Order I*. Versant submitted that compliance filing on April 1, 2022. Comments on that filing were due on or before April 22, 2022; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

81 *Id*. at P 23.

82 The Conn. Light & Power Co., 178 FERC ¶ 62,015 (Jan. 10, 2022).

83 CL&P and Brookfield each requested rehearing and/or clarification of the *Sterling IA Order* on Dec. 8, 2021.

84 *The Conn. Light and Power Co.*, 178 FERC ¶ 61,206 (Mar. 24, 2022) ("*Sterling IA Allegheny Order*").

85 *The Conn. Light and Power Co.*, 179 FERC ¶ 62,110 (May 26, 2022) (notice of denial by operation of law of rehearing of the *Sterling IA Allegheny Order*).

86 *Versant Power*, 178 FERC ¶ 61,159 (Mar. 7, 2022) ("*Versant Order 676-I Compliance Filing Order I*").

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

In accordance with *Order 864*[87] and *Order 864-A,*[88] and extensions of time granted, New England's transmission-owning public utilities submitted their *Order 864* compliance filings, with specific dockets and filing dates identified in the following table. The FERC has addressed a number of the compliance filings, with some yet to be acted on, and others submitting further compliance filings (generally to reflect a January 27, 2020 effective date). The *Order 864* compliance proceedings that remain open are as follows:

Docket(s)	Transmission Provider	Date of Last Filing	Date Accepted
ER21-1130 ER20-2572	New England TOs (RNS)	Feb 18, 2022	Pending
ER20-2429	Central Maine Power ("CMP") (LNS)	May 6, 2022	Pending
ER21-1702	CMP (Schedule 1 Appendix A Implem. Rule)	Feb 28, 2022	Pending
ER21-1654	CL&P (LNS)	Feb 28, 2022	Pending
ER21-1295	Eversource (CL&P, PSNH, NSTAR) (LNS; Schedule 21-ES)	Feb 23, 2022	Pending
ER21-1154	FG&E (LNS)	Feb 23, 2022	Pending
ER21-1694	Green Mountain Power	Feb 18, 2022	Pending
ER20-1089	New England Elec. Trans. Corp.	Feb 18, 2022	Accepted Jun 7, 2022
ER20-1087	New England Hydro Trans. Corp.	Feb 18, 2022	Accepted Jun 7, 2022
ER20-1088	New England Hydro Trans. Elec. Co.	Feb 18, 2022	Accepted Jun 7, 2022
ER21-1241	NEP (LNS)	Feb 28, 2022	Pending
ER20-2551	NEP (Schedule 21-NEP and TSA-NEP-22 Compliance Revisions)	Jul 30, 2020	Pending
ER20-2219	NEP (Tariff No. 1)	Jun 29, 2020	Pending
ER20-2553	NEP (MECO/Nantucket LSA)	Jul 30, 2020	Pending
ER21-1293	NSTAR (LNS)	Feb 23, 2022	Pending
ER22-1850	UI	May 10, 2022	Pending
ER21-1709	VTransco (LNS)	Feb 22, 2022	Pending
ER20-2594	VTransco (1991 VTA)	Feb 25, 2022	Accepted Jun 7, 2022
ER20-2133 -001, -002	Versant Power	Nov 22, 2021	Conditionally, Feb 28, 2022

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

♦ ***ER20-2429 (UI)***. On May 10, 2022, UI submitted further *Order 864* compliance filing changes, with changes to Schedule 21-UI including revisions to its rate base adjustment mechanism, Attachment D amortization

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[87] *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 Accumulated Deferred Income Taxes ("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 ("ADIT Worksheet"). The ***ADIT Worksheet*** must contain the following five specific categories of information: (i) how any ADIT accounts were re-measured and the excess or deficient ADIT contained therein ("***Category 1 Information***"); (ii) is the accounting for any excess or deficient amounts in Accounts 254 (Other Regulatory Liabilities) and 182.3 (Other Regulatory Assets) ("***Category 2 Information***"); (iii) whether the excess or deficient ADIT is protected (and thus subject to the Tax Cuts and Jobs Act's normalization requirements) or unprotected ("***Category 3 Information***"); (iv) the accounts to which the excess or deficient ADIT are amortized ("***Category 4 Information***"); and (v) the amortization period of the excess or deficient ADIT being returned or recovered through the rates ("***Category 5 Information***"). In addition, the FERC stated that it expects public utilities to identify each specific source of the excess and deficient ADIT, classify the excess or deficient ADIT as protected or unprotected, and list the proposed amortization period associated with each classification or source.

[88] *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*").

of excess or deficient ADIT, and a new permanent worksheet (Attachment M) that will be used to annually track information related to excess or deficient ADIT.

♦ ***ER20-2429 (CMP - LNS)***. On May 6, 2022, CMP further supplemented its March and April 2022 compliance filings with a PDF version of the Blank Permanent ADIT Worksheet and Permanent Remeasurement Worksheet and Worksheet Supporting Unprotected Plant and Non Plant (Excess) Deficient Balances in the eTariff record. No comments on CMP's May 6, 2022 compliance filing were submitted and that filing, as supplemented, is pending before the FERC.

♦ ***ER20-1089 (New England Elec. Trans. Corp.); ER20-1087 (New England Hydro Trans. Corp.); ER20-1088 (New England Hydro Trans. Elec. Co.); and ER20-2594 (VTransco (1991 VTA)):*** On June 7, the FERC accepted the *Order 864* compliance filings by New England Electric Transmission, New England Hydro Transmission Corporation, New England Hydro Transmission Electric Company,[89] and Versant Transco (its 1991 VTA).[90]

XII. Misc. - Administrative & Rulemaking Proceedings

- **New England Gas-Electric Forum (AD22-9)**

On May 19, 2022, the FERC announced that it will hold a forum, on September 8, 2022 in Burlington, VT, to discuss and achieve a greater understanding among stakeholders in defining the electric and natural gas system challenges in the New England Region.

- **NOI: Dynamic Line Ratings (AD22-5)**

On February 17, 2022, the FERC issued a notice of inquiry ("NOI")[91] seeking comments on (i) whether and how the required use of dynamic line ratings ("DLR") is needed to ensure just and reasonable wholesale rates; (ii) whether the lack of DLR requirements renders current wholesale rates unjust and unreasonable; (iii) potential criteria for DLR requirements; (iv) the benefits, costs, and challenges of implementing DLRs; (v) the nature of potential DLR requirements; and (vi) potential timeframes for implementing DLR requirements. This NOI represents the first step in the FERC's effort to gather more information about the costs and benefits, and potentially mandating the use, of DLRs. A more detailed summary was provided to the Transmission Committee and is posted on the Transmission Committee's webpage.

Initial comments were due ***April 25, 2022*** and filed by: ISO-NE; DC Energy; Eversource; Clean Energy Parties; Potomac Economics; CT DEEP; NERC; US DOE; CAISO; MISO; NYISO; Org of MISO States; PJM, SPP; SPP MMU; AEP; Alliant; APPA; APS; AZ PUC; Clean Energy Entities; Dayton Power; EEI; ELCON; Entergy; IN Util. Reg. Comm.; ITC; LA DPW; MISO TOs; NRECA; NYISO TOs; PPL; R Street Institute; Southern Co.; TAPS; Tri-State; Electricity Canada; Electric Grid Monitoring; Line Vision; Idaho Power.

Reply comments were due on or before ***May 25, 2022***[92] and were filed by: AEP, Clean Energy Entities,[93] EEI, Joint Consumer Advocates, MISO TOs, and the R Street Institute. This matter is pending before the FERC.

- **Improving Generating Units Winter Readiness (AD22-4)**

On April 27-28, 2022, the FERC convened a joint technical conference with NERC and its Regional Entities to discuss how to improve the winter-readiness of generating units, including best practices, lessons learned and increased use of the NERC Guidelines, as recommended in the Joint February 2021 Cold Weather Outages

[89] *New England Elec. Transmission Corp., New England Hydro Transmission Elec. Co., New England Hydro Transmission Corp.*, Docket Nos. ER20-1087-002; ER20-1088-002; ER20-1089-002 (June 7, 2022) (unpublished letter order).

[90] *Vermont Transco, LLC*, Docket No. ER20-2594-002 (June 7, 2022) (unpublished letter order).

[91] *Implementation of Dynamic Line Ratings*, 178 FERC ¶ 61,110 (Feb. 17, 2022) ("*Dynamic Line Ratings NOI*").

[92] The *Dynamic Line Ratings NOI* was published in the Fed. Reg. on Feb. 24, 2022 (Vol. 87, No. 37) pp. 10,349-10,354.

[93] The "Clean Energy Entities" are the Working for Advanced Transmission Technologies Coalition ("WATT"), ACPA, AEE, and SEIA.

Report.[94] Panels included discussion of (i) cold weather preparedness plans; (ii) planning, engineering and technologies for cold weather preparedness; (iii) implementing cold weather preparedness plans for reliable operations; and (iv) communications, coordination, training, and education for cold weather operations. Speaker materials have been posted in eLibrary.

- **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").[95] The Transmission Task Force is 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 the meetings 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."[96] New England is represented by Commissioners Riley Allen (VT PUC) and Matt Nelson (Chair, MA DPU).

Public Meetings.

♦ ***Nov 10, 2021***. The first Joint Federal-State Task Force meeting, which focused on incorporating state perspectives into regional transmission planning, was convened on November 10, 2021. A transcript of this meeting is posted in eLibrary. Comments on the issues discussed at that meeting were filed by: AEP, LA PSC, MI PSC, PJM, and Public Citizen.

♦ ***Feb 16, 2022***. A second meeting was held February 16, 2022 in Washington, DC. The agenda included a discussion, for purposes of transmission planning and cost allocation, specific categories and types of transmission benefits that transmission providers should consider and cost allocation principles, methodologies, and decision processes. A transcript of this meeting is posted in eLibrary. Post-meeting comments addressing issues raised during the February 16 meeting and identified in the agenda issued February 2, 2022 were due on or before April 1, 2022 and were filed by AZ PSC, NJ PBU, NARUC, ND PSC, OH PUC Office of the Federal Energy Advocate, VA State Corp. Comm., Americans for a Clean Energy Grid, ITC, PJM, and Sunflower Electric.

♦ ***May 6, 2022***. A third meeting was held virtually on May 16, 2022. Discussion addressed (i) the generator interconnection queue processes and current backlog; and (ii) cost allocation for generator interconnection-related network upgrades, including participant funding. A transcript of this meeting was posted in eLibrary on May 18, 2022. The FERC invited post-meeting comments addressing issues raised during and in the agenda for the May 6 meeting. Those comments were due on June 1, 2022 and were filed by: AEP, Ameren, Clean Energy Coalition, EEI, Invenergy Transmission, MISO, Old Dominion Electric Cooperative, Omaha Power District, PJM, and Xcel Energy.

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[94] *See The February 2021 Cold Weather Outages in Texas and the South Central United States - FERC, NERC and Regional Entity Staff Report* at pp 18, 192 (Nov. 16, 2021), https://www.ferc.gov/news-events/news/final-report-february-2021-freeze-underscores-winterization-recommendations.

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

[96] 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.

♦ ***July 20, 2022***. A fourth meeting will be held in San Diego, CA, on July 20, 2022. Suggestions for agenda items for the fourth JFSTF meeting were filed by: ACORE, AEP, Large Public Power Council, NRDC, and Orsted.

- **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 sought 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.

Post-technical conference comments were filed by: CAISO; MISO; NYISO; PJM; AEP; City of New Orleans; City of New York; Columbia Law School's Sabin Center for Climate Change Law; EDF and Sabin Center for Climate Change Law; EEI; EPSA; Eversource; Exelon, Jupiter Intelligence; Louisville Gas and Electric Company and Kentucky Utilities Company; MI PSC; NRDC, Sierra Club, Sustainable FERC Project, and UCS; Old Dominion Electric Cooperative ("ODEC"); NERC; and C. Wright. On October 14, 2022, Entergy answered the comments submitted by City of New Orleans.

Since the last Report, and as described below, the FERC issued an *Extreme Weather Vulnerability Assessments NOPR* (*see* RM22-16 below). The NOPR proposed to require transmission providers to submit one-time informational reports describing their current or planned policies and processes for conducting extreme weather vulnerability assessments. Reporting on this proceeding will conclude with this Report.

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

ISO/RTO Reports. On April 21, 2022, the FERC issued an order[97] directing each independent system operator ("ISO") and regional transmission organization ("RTO"), including ISO-NE, to submit on or before ***October 17, 2022*** a report that describes: (1) current system needs given changing resource mixes and load profiles; (2) how it expects its system needs to change over the next five and 10 years; (3) whether and how it plans to reform its energy and ancillary services ("EAS") markets to meet expected system needs over the next five and 10 years; and (4) information about any other reforms, including capacity market reforms and any other resource adequacy reforms that would help it meet changes in system needs. Public comments in response to the RTO/ISO reports may be submitted within 60 days following the filing of the reports. The FERC will review the reports and comments to determine whether further action is appropriate.

[97] *Modernizing Wholesale Electricity Market Design*, 179 FERC ¶ 61,029 (Apr. 21, 2022) ("*Order Directing Reports*").

2021 Technical Conferences. The *Order Directing Reports* follows a series of staff-led technical conferences, convened in 2021 and summarized in previous Reports, addressing ISO/RTO resource adequacy[98] and energy and ancillary services markets.[99]

- **Increasing Market and Planning Efficiency Through Improved Software Tech Conf (Jun 21-23, 2022) (AD10-12)**

On February 24, 2022, the FERC announced that it will hold its 13th annual technical conference addressing increasing Real-Time and Day-Ahead market efficiency through improved software from June 21-23. A detailed agenda with the list of and times for the selected speakers was published on the FERC's website[100] and in eLibrary on May 27, 2022. In its May 27 supplemental notice of this technical conference, the FERC stated that it will accept comments following the conference, with a deadline of July 29, 2022.

- **NOPR: Extreme Weather Vulnerability Assessments (RM22-16; AD21-13)**

On June 16, 2022, the FERC issued a notice[101] proposing to require transmission providers to submit one-time informational reports describing their current or planned policies and processes for conducting extreme weather vulnerability assessments[102] (how they establish a scope for their extreme weather vulnerability assessments, develop inputs, identify vulnerabilities and determine exposure to extreme weather hazards, estimate the costs of impacts, and develop mitigation measures to address extreme weather risks). Initial comments are due [60 days after the date of publication in the *Federal Register*].

- **NOPR: Interconnection Reforms (RM22-14)**

On June 16, 2022, the FERC issued a notice of proposed rulemaking ("NOPR"),[103] more than 400 pages long, that proposes reforms to the *pro forma* Large Generator Interconnection Procedures ("LGIP"), *pro forma* Small Generator Interconnection Procedures ("SGIP"), *pro forma* Large Generator Interconnection Agreement ("LGIA"), and *pro forma* Small Generator Interconnection Agreement ("SGIA") to address interconnection queue backlogs, improve certainty, and prevent undue discrimination for new technologies. Initial comments and reply

98 The FERC held two staff-led technical conferences addressing resource adequacy, one on Mar. 23, 2021 (with post-conference comments focused on PJM-specific issues) and the other on May 25, 2021 (focused on the wholesale markets administered by ISO-NE). Following the Mar. 23 conference, more than 45 sets of initial comments were filed, including by: AEE, Calpine, Cogentrix, Dominion, Exelon, FirstLight, LS Power, NESCOE, NEPGA, NRG, PSEG, Shell, Vistra, CT DEEP, EEI, EPSA, and NRECA/APPA. 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"). Following the May 25 conference, comments were filed by: AEE, Calpine, CT Parties, Dominion, Eversource, MMWEC, NESCOE, NEPGA, NextEra, NRG, Public Interest Orgs, Vistra, AEMA, EPSA, RENEW.

99 The FERC held two staff-led technical conferences addressing ISO/RTO EAS markets, one on Sept. 14, 2021; the second on Oct. 12, 2021. Transcripts of both technical conferences are posted in eLibrary. In advance of the EAS technical conferences, FERC staff issued on Sept. 7, 2021 a White Paper entitled "Energy and Ancillary Services Market Reforms to Address Changing System Needs" summarizing recent EAS markets reforms as well as reforms then under consideration. Initial comments on the topics discussed during the EAS technical conferences were filed by: ISO-NE, Appian Way Energy Partners, Constellation, Dominion, Envir. Defense Fund, FirstLight, LS Power, CAISO, MISO, NYISO, PJM, SPP MMU, ACPA, Clean Energy Organizations, EEI, Energy Trading Institute, EPRI, EPSA, Middle River Power, National Hydropower Assoc., NYSERDA, PJM Providers Group, and Public Citizen. Reply comments were filed by EPRI, NERC and its Regional Entities and Vistra.

100 https://www.ferc.gov/industries-data/electric/power-sales-and-markets/increasing-efficiency-through-improved-software.

101 *One-Time Informational Reports on Extreme Weather Vulnerability Assessments; Climate Change, Extreme Weather, and Elec. Sys. Rel.*, 179 FERC ¶ 61,196 (June 16, 2022) ("*Extreme Weather Vulnerability Assessments NOPR*").

102 "Extreme weather vulnerability assessments" are proposed to be defined as "analyses that identify where and under what conditions jurisdictional transmission assets and operations are at risk from the impacts of extreme weather events, how those risks will manifest themselves, and what the consequences will be for system operations".

103 *Improvements to Generator Interconnection Procedures and Agreements*, 179 FERC ¶ 61,194 (June 16, 2022) ("*Interconnection* Reforms *NOPR*").

comments are due [100 days (late September) and 130 days (late October), respectively, after the date of publication in the *Federal Register*].

The proposed reforms fall into three main categories: (1) reforms to implement a first-ready, first-served cluster study process; (2) reforms to increase the speed of interconnection queue processing; and (3) reforms to incorporate technological advancements to the interconnection process. Within each of these categories, the FERC proposes a wide array of reforms, and requests comment.

To implement the **first-ready, first-served cluster study process**, the FERC proposes to:

- Require transmission providers offer an alternative option for an informational interconnection study that would not require a project enter the interconnection queue;
- Make cluster studies the required interconnection study method under the *pro forma* LGIP;
- Allocate the shared costs of the cluster studies so that 90% of the applicable study costs are allocated to interconnection customers on a pro rate basis based on the requested MWs included in the applicable cluster, and 10% of the applicable study costs are allocated to interconnection customers on a per capita basis based on the number of interconnection requests in the applicable cluster;
- Require transmission providers to allocate network upgrade costs to interconnection customers within a cluster using a proportional impact method, in which the transmission provider will determine the degree to which each generating facility in the cluster contributes to the need for a specific network upgrade;
- Allow interconnection customers in an earlier-in-time cluster to share the costs of network upgrades with interconnection customers who will significantly benefit from those upgrades but would not share the cost of the network upgrades solely by virtue of being in a later cluster;
- Increase study deposits based on the size of the generating facility from $35,000 to $250,000;
- Require more stringent site control requirements, and proposes to require an interconnection customer to demonstrate 100% site control for a proposed generating facility when they submit the interconnection request;[104]
- Implement a commercial readiness framework whereby interconnection customers must show demonstrable milestones towards commercial readiness in order to enter the cluster, such as an executed term sheet, reasonable evidence the project was selected in a resource plan, or a provisional LGIA;[105]
- Impose withdrawal penalties when the interconnection customer withdraws from the interconnection queue.[106]

To **increase the speed of the interconnection queue process**, the FERC proposes to:

- Eliminate the "reasonable efforts" standard for transmission providers completing interconnection studies and instead impose firm study deadlines and establish penalties that would apply when transmission providers fail to meet these deadlines. The penalty imposed would be $500 per day that the study is late and would be distributed to interconnection customers on a pro rata basis;

[104] The FERC proposes to limit the option to provide a financial deposit in lieu of site control and would only allow this option when regulatory limitations prohibit the interconnection customer from obtaining site control. In such instances, the interconnection customer would submit a deposit of $10,000 per MW, subject to a floor of $500,000 and a ceiling of $2 million.

[105] *Id.* at P 128.

[106] The proposed withdrawal penalty will increase as the interconnection customer moves through the interconnection queue and proposes a chart demonstrating the possible penalties at P 144.

- Add an entirely *pro forma* affected system study process to address the current lack of uniformity in the study of affected systems, which results in late-stage withdrawals, re-studies and increased costs to remaining interconnection customers;
- Establish two new *pro forma* agreements, a *pro forma* Affected System Study Agreement (new Appendix 15) and a *pro forma* Affected Systems Facilities Construction Agreement (new Appendix 16);
- Implement an optional resource solicitation study that can be performed by entities required to conduct a resource plan or solicitation. Under this proposed study process, a resource planning agency (such as a state agency or load-serving entity implementing a state mandate) would facilitate a study to group together interconnection requests associated with the qualifying resource solicitation process, and the resources vying for selection in a qualifying state resource solicitation process would be studied together for the purposes of informational interconnection studies.

Finally, as **technological advances to the interconnection process**, the FERC proposes to:

- Require transmission providers to allow more than one resource to co-locate on a shared site behind a single point of interconnection and share a single interconnection request;
- Change the way in which transmission providers assess an addition of a generating facility to an interconnection request, requiring that transmission providers evaluate a proposed addition as long as the addition does not change the requested interconnection service level;
- Enable customers with unused interconnection capacity share that surplus capacity with other resources as long as the original interconnection customer executes an LGIA or requests filing of an unexecuted LGIA;
- Require transmission providers, at the request of the interconnection customer to use operating assumptions for interconnection studies that reflect the proposed operation of an electric storage resource or co-located storage resource; and
- Require transmission providers to evaluate grid-enhancing solutions and file an annual informational report on their use of grid-enhancing technologies.

The FERC proposes to require compliance within 180 days of a final rule in this proceeding. Compliance would require transmission providers to file updates to their *pro forma* LGIA, LGIP, SGIA and SGIP, as applicable. If you have any questions concerning the *Interconnection Reforms NOPR*, please contact Margaret Czepiel (202-218-3906; mczepiel@daypitney.com) or Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **NOPR: Transmission System Planning Performance Requirements for Extreme Weather (RM22-10)**

On June 16, 2022, the FERC issued a notice[107] proposing to require that NERC modify Reliability Standard TPL-001-5.1 (Transmission System Planning Performance Requirements) within one year of the effective date of a final rule in this proceeding to address reliability concerns pertaining to transmission system planning for extreme heat and cold weather events that impact the reliable operations of the Bulk-Power System. Specifically, the FERC proposed modifications to TPL-001-5.1 to require: (i) development of benchmark planning cases; (ii) planning for extreme heat and cold events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios; and (iii) corrective action plans that include mitigation for any instances where performance requirements for extreme heat and cold events are not met. Initial comments are due [60 days after the date of publication in the *Federal Register*].

[107] *Transmission System Planning Performance Requirements for Extreme Weather*, 179 FERC ¶ 61,195 (June 16, 2022) ("*Extreme Weather Transmission System Planning NOPR*").

- **NOI: Rate Recovery, Reporting, and Accounting Treatment of Industry Association Dues and Certain Civic, Political, and Related Expenses (RM22-5)**

On December 16, 2021, the FERC issued a notice of inquiry[108] seeking comments on (i) the rate recovery, reporting, and accounting treatment of industry association dues and certain civic, political, and related expenses; (ii) the ratemaking implications of potential accounting and reporting changes; (iii) whether additional transparency or guidance is needed with respect to defining donations for charitable, social, or community welfare purposes; and (iv) a framework for guidance should the FERC determine action is necessary to further define the recoverability of industry association dues charged to utilities and/or utilities' expenses from civic, political, and related activities. Initial comments were due February 22, 2022 and were filed by AGA, APPA, EEI, EPRI, Harvard Electricity Law Institute, INGA, Joint RTO Commenters,[109] MA AG, National Grid, NEI, Nexamp, NRECA, Public Citizen, Public Interest Organizations, Ratepayers, Sunova, and UCS. Reply comments were due on or before March 23, 2022 and were filed by, among others: DTE, MA AG, NECOS, AGA, EEI, INGA, Joint Consumer Advocates, and WIRES. Since the last Report, Joint RTO Commenters replied to NECOS' discussion and characterization of the Initial Joint RTO Comments and a question of First Amendment constitutional law. This matter is pending before the FERC.

- **NOPR: Internal Network Security Monitoring for High and Medium Impact BES Cyber Systems (RM22-3)**

On January 20, 2022, the FERC issued a NOPR[110] proposing to direct NERC to develop and submit for FERC approval new or modified Reliability Standards that require internal network security monitoring ("INSM")[111] within a trusted Critical Infrastructure Protection networked environment for high and medium impact Bulk Electric System ("BES") Cyber Systems. The FERC stated that "including INSM requirements in the CIP Reliability Standards would ensure that responsible entities maintain visibility over communications between networked devices within a trust zone (i.e., within an ESP), not simply monitor communications at the network perimeter access point(s), i.e., at the boundary of an ESP as required by the current CIP requirements. In the event of a compromised ESP, improving visibility within a network would increase the probability of early detection of malicious activities and would allow for quicker mitigation and recovery from an attack."[112]

Comments on the *Internal Network Security Monitoring NOPR* were due on or before March 28, 2022.[113] Comments were filed by: the IRC, NERC, EEI, EPSA, TAPS, Bonneville Power Admin., Consumers Energy, Cynalytica, CA Department of Water Resources, Electricity Canada, Entergy, Idaho Power, Juniper Networks, ITC, Microsoft, North American Generator Forum, Nozomi Networks, Operational Technology Cybersecurity Coalition, the US Bureau of Reclamation, and T. Conway. This matter is pending before the FERC.

- **NOI: Reactive Power Capability Compensation (RM22-2)**

On November 18, 2021, the FERC issued a notice of inquiry[114] seeking comments on reactive power capability compensation and market design. Specifically, the FERC seeks comments on whether (i) the AEP

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108 *Rate Recovery, Reporting, and Accounting Treatment of Industry Association Dues and Certain Civic, Political, and Related Expenses*, 177 FERC ¶ 61,180 (Dec. 16, 2021) ("*Dues & Expenses NOI*").

109 "Joint RTO Commenters" are PJM Interconnection, L.L.C. ("PJM"), California Independent System Operator Corp. ("CAISO"), Midcontinent Independent System Operator, Inc. ("MISO"), and Southwest Power Pool ("SPP").

110 *Internal Network Security Monitoring for High and Medium Impact Bulk Electric System Cyber Systems*, 178 FERC ¶ 61,038 (Jan. 20, 2022) ("*Internal Network Security Monitoring NOPR*").

111 INSM is a subset of network security monitoring that is applied within a "trust zone," such as an Electronic Security Perimeter ("ESP"), and is designed to address situations where vendors or individuals with authorized access are considered secure and trustworthy but could still introduce a cybersecurity risk to a high or medium impact BES Cyber System.

112 *Id.* at P 2.

113 The *Internal Network Security Monitoring NOPR* was published in the *Fed. Reg.* on Jan. 27, 2022 (Vol. 87, No. 18) pp. 4,173-4,180.

114 *Rate Recovery, Reporting, and Accounting Treatment of Industry Association Dues and Certain Civic, Political, and Related Expenses*, 177 FERC ¶ 61,180 (Dec. 16, 2021) ("*Dues & Expenses NOI*").

Methodology remains a just and reasonable approach to determining reactive power revenue requirements in all circumstances; (ii) other potential alternative methodologies not based on the costs of the particular resource(s) at issue in a given proceeding should be considered or better used to develop reactive power capability revenue requirements; and (iii) resources interconnected to a distribution system and participating in wholesale markets are technically capable of providing reactive power to the transmission system in such a way that they should be eligible for reactive power capability compensation through transmission rates. Initial comments were due February 21; Reply Comments, March 23, 2022. Initial comments were filed by over 35 parties. Reply comments were filed by: Ameren, Clean Energy Coalition, DE Shaw, EDF, EEI, EPSA, Joint Customers,[115] MISO TOs, PJM IMM, PSEG, Vistra, and N. Bhushan. This matter is pending before the FERC.

- ***Transmission NOPR*** **(RM21-17)**

Following its ANOPR process,[116] the FERC issued on April 21, 2022 a NOPR[117] that would require public utility transmission providers to:

(i) conduct long-term regional transmission planning on a sufficiently forward-looking basis to meet transmission needs driven by changes in the resource mix and demand;

(ii) more fully consider dynamic line ratings and advanced power flow control devices in regional transmission planning processes;

(iii) seek the agreement of relevant state entities within the transmission planning region regarding the cost allocation method or methods that will apply to transmission facilities selected in the regional transmission plan for purposes of cost allocation through long-term regional transmission planning;

(iv) adopt enhanced transparency requirements for local transmission planning processes and improve coordination between regional and local transmission planning with the aim of identifying potential opportunities to "right-size" replacement transmission facilities; and

(v) revise their existing interregional transmission coordination procedures to reflect the long-term regional transmission planning reforms proposed in this NOPR.

In addition, the *Transmission NOPR* would not permit public utility transmission providers to take advantage of the construction-work-in-progress ("CWIP") incentive for regional transmission facilities selected for purposes of cost allocation through long-term regional transmission planning and would permit the exercise of federal rights of first refusal ("ROFR") for transmission facilities selected in a regional transmission plan for purposes of cost allocation, conditioned on the incumbent transmission provider with the federal ROFR for such regional transmission facilities establishing joint ownership of the transmission facilities. While the ANOPR sought comment on reforms related to cost allocation for interconnection-related network upgrades, interconnection

[115] "Joint Customers" are Old Dominion Electric Cooperative ("ODEC"), Northern Virginia Electric Cooperative, Inc. ("NOVEC"), and Dominion Energy Services, Inc. on behalf of Virginia Electric and Power Company d/b/a Dominion Energy Virginia ("Dominion").

[116] *See 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*"). The FERC convened a tech. conf. on Nov. 15, 2021, to examine in detail the issues and potential reforms described in the *ANOPR*. Speaker materials and a transcript of the tech. conf. are posted in FERC's eLibrary. Pre-technical conference comments were submitted by over 175 parties, including by: NEPOOL, ISO-NE, AEE, Anbaric, Avangrid, BP, CPV, Dominion, EDF, EDP, Enel, EPSA, Eversource, Exelon, LS Power, MA AG, MMWEC, National Grid, NECOS, NESCOE, NextEra, NRDC, Orsted, Shell, UCS, VELCO, Vistra, Potomac Economics, ACORE, ACPA/ESA, APPA, EEI, ELCON, Industrial Customer Orgs, LPPC, MA DOER, NARUC, NASUCA, NASEO, NERC, NRECA, SEIA, State Agencies, TAPS, WIRES, Harvard Electric Law Initiative; NYU Institute for Policy Integrity, New England for Offshore Wind Coalition, and the R Street Institute. *ANOPR* reply comments and post-technical conference comments were filed by over 100 parties, including: by: CT AG, Acadia Center/CLF, CT AG, Dominion, Enel, Eversource, LS Power, MA AG, MMWEC, NESCOE, NextEra, Shell, UCS, Vistra, ACPA/ESA, AEE, APPA, EEI, ELCON, Environmental and Renewable Energy Advocates, EPSA, Harvard ELI, NRECA, Potomac Economics, and SEIA. Supplemental reply comments were filed by WIRES, and a group of former military leaders and former Department of Defense officials, and ACPA/AEE/SEIA.

[117] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 179 FERC ¶ 61,028 (Apr. 21, 2022) ("*Transmission NOPR*").

queue processes, interregional transmission coordination and planning, and oversight of transmission planning and costs, the *Transmission NOPR* does not propose broad or comprehensive reforms directly related to these topics. The FERC indicated that it would continue to review the record developed to date and expects to address possible inadequacies through subsequent proceedings that propose reforms, as warranted, related to these topics.

A number of the elements of the *Transmission NOPR*, if adopted as part of a final rule, would result in some significant changes to how the region's transmission needs are identified, solutions are evaluated and selected, and costs recovered and allocated. A more fulsome high-level summary from NEPOOL Counsel of the *Transmission NOPR* was distributed to, and was reviewed with, the Transmission Committee, which will recommend whether NEPOOL should submit comments on the *Transmission NOPR*.

Comment Dates Extended. Following a number of requests for extensions of time, comments on the *Transmission NOPR* are due ***August 17, 2022***; reply comment ***September 19, 2022***. Thus far, the Clean Energy Coalition and Large Public Power Council have submitted comments.

If you have any questions concerning the *Transmission NOPR*, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Margaret Czepiel (202-218-3906; mczepiel@daypitney.com).

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

On March 18, 2021, the FERC issued a NOI[118] 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. On March 28, 2022, the Mississippi PSC moved to lodge its Protest and Response filed in a recent Complaint proceeding initiated and subsequently withdrawn by Voltus (EL21-12), to ensure its pleading is a part of the record of this proceeding. On March 29, 2022, the U.S. House Sustainable Energy and Environment Coalition ("SEEC") Power Sector Task Force urged the FERC to proceed to a NOPR that would eliminate the demand response Opt-Out. This matter remains pending before the FERC.

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

On December 17, 2020, the FERC issued a NOPR[119] 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.,[120] 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

[118] *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*").

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

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

Citizen. Reply comments were due May 6, 2021[121] 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.

- ***Order 881*: Managing Transmission Line Ratings (RM20-16)**

On December 16, 2021, the FERC issued its final rule, *Order 881*, on Managing Transmission Line Ratings.[122] In *Order 881*, the FERC reforms both the *pro forma* OATT and its regulations to improve the accuracy and transparency of transmission line ratings. Specifically, *Order 881* requires:

(vi) transmission providers to implement ambient-adjusted ratings on the transmission lines over which they provide transmission service;

(vii) ISO/RTOSs to establish and implement the systems and procedures necessary to allow transmission owners to electronically update transmission line ratings at least hourly;

(viii) 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); and

(ix) transmission providers to maintain a database of transmission owners' transmission line ratings and transmission line rating methodologies on the transmission provider's Open Access Same-Time Information System ("OASIS") site or other password-protected website.

Order 881 became effective March 14, 2022.[123]

Requests for rehearing and/or clarification. Requests for rehearing and/or clarification of *Order 881* were filed by ATC, EEI, ITC Holdings, MISO IMM, and the MISO TOs on January 18, 2022, but may be deemed denied by operation of law. On February 18, 2022, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[124] The Notice confirmed that the 60-day period during which a petition for review of *Order 881* can be filed with an appropriate federal court was triggered when the FERC did not act on the requests for rehearing of *Order 881*. 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."

The FERC issued that order on May 19, 2022 ("*Order 881-A*"),[125] modifying the discussion in *Order 881*, granting clarification in part, and continuing to reach the same result as in *Order 881*. Specifically, the FERC:

(i) continued to find that requiring transmission providers to apply the ambient-adjusted ratings ("AAR")[126] requirements set forth in pro forma OATT Attachment M to all transmission lines on which they provide transmission service, subject to certain exceptions, is just and reasonable;

(ii) clarified two aspects of the AAR requirements related to transmission providers' transmission protection relay settings ((1) if a transmission provider establishes higher transmission line ratings,

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

[122] *Managing Transmission Line Ratings*, Order No. 881, 177 FERC ¶ 61,179 (Dec. 16, 2021) ("*Order 881*").

[123] *Order 881* was published in the Fed. Reg. on Jan. 13, 2022 (Vol. 87, No. 9) pp. 2,244-2,307.

[124] *Managing Transmission Line Ratings*, 178 FERC ¶ 62,104 (Feb. 18, 2022) ("*Order 881 Notice of Denial of Rehearings by Operation of Law*").

[125] *Managing Transmission Line Ratings*, 179 FERC ¶ 61,125 (May 19, 2022) (*"Order 881-A")*.

[126] An ambient-adjusted rating is defined as a transmission line rating that: (1) applies to a time period of not greater than one hour; (2) reflects an up-to-date forecast of ambient air temperature across the time period to which the rating applies; (3) reflects the absence of solar heating during nighttime periods where the local sunrise/sunset times used to determine daytime and nighttime periods are updated at least monthly, if not more frequently; and (4) is calculated at least each hour, if not more frequently. *See* 18 CFR 35.28(b)(12) (2021); Pro Forma OATT attach. M, AAR Definition.

it will have to evaluate or reevaluate its applicable protection systems for that facility and (2) in a majority of situations the relay setting should exceed AAR values);

(iii) continued to require the use of AARs for a 10-day forward period;

(iv) declined to clarify or grant rehearing on the issue of a transmission line rating “floor”, which it declined to require in *Order 881*;

(v) did not change its position with respect to the five-degree requirement,[127] the daytime/nighttime ratings requirement,[128] the seasonal line ratings annual update requirement, data storage and sharing requirements, or the proposed implementation schedule (AAR implementation on congested transmission lines within one year from the date of the compliance filing and, for all other transmission lines, implementation within two years from the date of the compliance filing);

(vi) clarified that transmission providers have the discretion to post the required data to their OASIS site or an alternative password-protected website so long as users are able to access the data in a manner that is comparable to if it were posted to OASIS and subject to OASIS access requirements; and

(vii) clarified that *Order 881* did not revise the FERC’s existing CEII requirements (and that transmission line ratings and methodologies do not constitute CEII).

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

Supplemental NOPR. In light of comments already received in this proceeding,[129] the FERC issued on April 15, 2021 a *Supplemental NOPR*[130] 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 sought 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*.[131]

[127] The requirement that transmission providers implement AARs that update at least with every 5°F increment of temperature change, in order to meet the *pro forma* OATT Attachment M requirement that an AAR reflect an up-to-date forecast of ambient air temperature.

[128] The requirement that transmission providers incorporate solar heating into AARs by implementing separate AARs for daytime and nighttime periods, and to update the sunrise and sunset times used to calculate their AARs at least monthly, if not more frequently.

[129] 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.

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

[131] 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 <u>and</u> an additional 50-basis-point adder for transmission projects that demonstrate *ex post* cost savings that fall in the 90th percentile of transmission projects studied over the same sample period, as measured at the end of construction.
- ***ROE for Reliability Benefits***. A 50-basis-point adder for transmission projects that can demonstrate potential reliability benefits by providing quantitative analysis, where possible, as well as qualitative analysis.
- ***Abandoned Plant Incentive***. 100 percent of prudently incurred costs of transmission facilities selected in a regional transmission planning process that are cancelled or abandoned due to factors that are beyond the control of the applicant. Recovery from the date that the project is selected in the regional transmission planning process.
- ***Eliminate Transco Incentives***.

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.[132] Reply comments were also posted from New England State Parties,[133] Alliant/Consumers/DTE, AEP, Pacific Gas & Electric, Joint Consumer Advocates, and the American Clean Power Association ("ACPA").

September 10, 2021 Workshop. The FERC convened a workshop on September 10, 2021[134] to discuss certain performance-based ratemaking approaches, particularly shared savings, that may foster deployment of transmission technologies. The notice states that the workshop will explore: the maturity of the modeling approaches for various transmission technologies; the data needed to study the benefits/costs of such technologies; issues pertaining to access to or confidentiality of this data; the time horizons that should be considered for such studies; and other issues related to verifying forecasted benefits. The workshop also discussed whether and how to account for circumstances in which benefits do not materialize as anticipated and may explore other performance-based ratemaking approaches for transmission technologies seeking incentives under FPA section 219, particularly market-based incentives. The FERC issued an agenda for the workshop, which included the final workshop program and expected speakers, on August 23, 2021. The FERC supplemented that notice on September 9, 2021. On October 13, 2021, the FERC posted a transcript of the workshop in eLibrary.

Notice Inviting Post-Workshop Comments. On October 18, 2021, the FERC issued a notice inviting those interested to file post-workshop comments to address the issues raised during the workshop concerning incentives and shared savings. Comments were due on or before January 14, 2022 and were filed by APPA, CAISO, Clean Energy Parties,[135] EDF Renewables, EEI, the Industrial Energy Consumers of America ("IECA"), National Grid, PJM IMM, TAPS.

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

- ***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.

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

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

[134] 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).

[135] The "Clean Energy Parties" are: Working for Advanced Transmission Technologies ("WATT Coalition"), ACPA, AEE, American Council on Renewable Energy ("ACORE"), Natural Resources Defense Council ("NRDC"), and the Sustainable FERC Project.

XIII. FERC Enforcement Proceedings

Electric-Related Enforcement Actions

- **PacifiCorp (IN21-6)**

On April 15, 2021, in the FERC's first-ever Show Cause Order addressing alleged violations of NERC Reliability Standards,[136] the FERC directed PacifiCorp to show cause why it should not be found to have violated FPA section 215(b)(1) and section 39.2 of the FERC's regulations by failing to comply with Reliability Standard FAC 009-1 (Establish and Communicate Facility Ratings), Requirement R1, and the successor Reliability Standard FAC-008-3 (Facility Ratings), Requirement R6 (collectively, "FAC-009-1 R1"), which requires a transmission owner to establish and have facility ratings that are consistent with its Facility Ratings Methodology ("FRM"). An Enforcement investigation found that clearance measurements on a majority of PacifiCorp's transmission lines were incorrect under the National Electric Safety Code, which were used to calculate PacifiCorp's facility ratings, thus making PacifiCorp's facility ratings inconsistent with its FRM. Enforcement alleges that PacifiCorp was aware of incorrect clearances on its system since at least 2007 when FAC-009-1 R1 became mandatory, but failed to identify and remedy them in a timely manner, and PacifiCorp's violations began on August 31, 2009, when it implemented its FRM policy, and at least some of the violations continued until August 2017 when PacifiCorp completed remediation of all of its incorrect clearances to make them consistent with its FRM. Enforcement also pointed to the role of the violations in the Wood Hollow, Utah wildfire that lasted from June 23 to July 1, 2012. In light of these alleged violations, the FERC directed PacifiCorp to show cause why it should not be assessed civil penalties in the amount of ***$42 million***.

On July 16, 2021, PacifiCorp answered the PacifiCorp Show Cause Order, denying the alleged violations of FAC-009. Enforcement filed its reply on September 14, 2021. This matter remains pending before the FERC. (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).

Natural Gas-Related Enforcement Actions

- **Rover Pipeline, LLC and Energy Transfer Partners, L.P. (CPCN Show Cause Order) (IN19-4)**

On January 20, 2022, the FERC issued an order establishing a hearing to determine whether Rover Pipeline, LLC ("Rover") and its parent company Energy Transfer Partners, L.P. ("ETP" and collectively with Rover, "Respondents") violated section 157.5 of the FERC's regulations and to ascertain certain facts relevant for any application of the FERC's Penalty Guidelines.[137]

As previously reported, on March 18, 2021, the FERC issued a show cause order[138] 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 ("CPCN") under NGA section 7(c).[139] The FERC directed Respondents to show cause why they should not be assessed civil penalties in

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

[137] *Rover Pipeline, LLC, and Energy Transfer Partners, L.P.*, 178 FERC ¶ 61,028 (Jan. 20, 2022) ("*Rover/ETP Hearings Order*").

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

[139] 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

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 CPCN Cause Order*, asserting that the FERC should dismiss this matter and decline to initiate an enforcement action. On July 21, 2021, Enforcement Staff answered Rover/ETP's answer, stating the evidence supports a finding that Rover violated the FERC's Regulations and should be assessed the civil penalty identified in the *Rover/ETP Show Cause Order*. Rover answered the July 21 answer on September 15.

Hearings. As previously reported, ALJ Joel DeJesus will be the presiding judge for hearings in this matter. On March 8, 2022, Chief Judge Cintron issued an order extending the procedural time standards for this proceeding. Based on that order, the deadlines for the commencement of the hearing is now March 6, 2023 and the deadline to issue the initial decision is now June 20, 2023. A virtual prehearing conference was also held on March 8, a transcript of which is posted in eLibrary.

- **Rover and ETP (Tuscarawas River HDD Show Cause Order) (IN17-4)**

On December 16, 2021, the FERC issued a show cause order[140] in which it directed Rover and ETP (together, "Respondents") to show cause why they should not be found to have violated NGA section 7(e), FERC Regulations (18 C.F.R. § 157.20); and the FERC's Certificate Order,[141] by: (i) intentionally including diesel fuel and other toxic substances and unapproved additives in the drilling mud during its horizontal directional drilling ("HDD") operations under the Tuscarawas River in Stark County, Ohio, in connection with the Rover Pipeline Project;[142] (ii) failing to adequately monitor the right-of-way at the site of the Tuscarawas River HDD operation; and (iii) improperly disposing of inadvertently released drilling mud that was contaminated with diesel fuel and hydraulic oil. The FERC directed Respondents to show why they should not be assessed civil penalties in the amount of ***$40 million***.

On March 21, 2022, Respondents answered and denied the allegations in the *Rover/ETP CPCN Show Cause Order*. On April 20, 2022, OE Staff answered Respondents' March 21 answer. On May 13, Respondents submitted a surreply, reinforcing their position that "there is no factual or legal basis to hold either [Respondent] liable for the intentional wrongdoing of others that is alleged in the Staff Report." Also since the last Report, the FERC denied Respondents' request for rehearing of the FERC's January 21, 2022 designation notice.[143] This matter is pending before the FERC.

- **BP (IN13-15)**

On December 17, 2020, the FERC issued *Opinion 549-A*,[144] a 159-page decision addressing arguments raised on rehearing requested of *Opinion 549.*[145] *Opinion 549-A* modifies the discussion in *Opinion 549*, but

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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.

[140] *Rover Pipeline, LLC, and Energy Transfer Partners, L.P.,* 177 FERC ¶ 61,182 (Dec. 16, 2021) ("*Rover/ETP Tuscarawas River HDD Show Cause Order*").

[141] *Rover Pipeline LLC,* 158 FERC ¶ 61,109 (2017), *order on clarification & reh'g*, 161 FERC ¶ 61,244 (2017), *Petition for Rev.*, *Rover Pipeline LLC v. FERC*, No. 18-1032 (D.C. Cir. Jan. 29, 2018) ("Certificate or Certificate Order").

[142] The Rover Pipeline Project is an approximately 711 mile long interstate natural gas pipeline designed to transport gas from the Marcellus and Utica shale supply areas through West Virginia, Pennsylvania, Ohio, and Michigan to outlets in the Midwest and elsewhere.

[143] *Rover Pipeline, LLC, and Energy Transfer Partners, L.P.,* 179 FERC ¶ 61,090 (May 11, 2022) ("*Designation Notice Rehearing Order*"). The "Designation Notice" provided updated notice of designation of the staff of the FERC's Office of Enforcement ("OE") as non-decisional in deliberations by the FERC in this docket, with the exception of certain staff named in that notice.

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

[145] *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

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.[146] Opinion 549-A revised Ordering Paragraph (C) to direct the disgorged profits to non-profits that disburse the Low Income Home Energy Assistance Program of Texas funds, rather than to the Texas Department of Housing.[147]

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[148] 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.[149]

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.

Hearing Procedures. 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.[150] On July 27, Chief Judge Cintron designated Judge

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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*")).

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

[147] *Id*. at P 319.

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

[149] 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.

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

Suzanne Krolikowski as the Presiding ALJ and established an extended Track III Schedule[151] for the proceeding. Judge Krolikowski scheduled and convened on August 26, 2021 a prehearing conference. Judge Krolikowski issued an order confirming her rulings from the August 26 prehearing conference and establishing a procedural schedule that calls for, among other dates, pre-hearing briefs by July 25, 2022, hearings (estimated to take 2-3 weeks) to begin on August 15, 2022, and an initial decision on January 9, 2023. In light of the settlement judge procedures undertaken, Chief Judge Cintron extended the hearing commencement and initial decision deadlines to September 26, 2022, and February 20, 2023, respectively.

Respondents requested reconsideration or in the alternative permission to file an interlocutory appeal of Judge Krolikowski's March 24 order confirming his bench rulings ("Reconsideration Motion"). OE Staff opposed the Motion. On April 25, finding Respondents had not raised any new arguments that would merit reconsideration of his prior rulings, nor had Respondents identified any "exceptional circumstances" requiring interlocutory appeal, Judge Krolikowski denied Respondents' Reconsideration Motion. Respondents May 2, 2022 interlocutory appeal was denied on May 9, 2022.[152]

Since the last Report, procedural activity in this proceeding has included continued litigation over subpoena requests and the rights of certain entities to intervene as parties to this proceeding, issuance by the Chief ALJ and Presiding Judge of revised procedural schedules (extending the Track III procedural time standards for this proceeding, with the deadlines for the commencement of the hearing and for issuing the initial decision (November 15, 2022 and April 27, 2023, respectively), as well as the intermediate deadlines, extended by roughly seven weeks.

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.
  - On March 25, 2022, after procedural developments summarized in previous Reports, the FERC issued to Iroquois a certificate of public convenience and necessity, authorizing it to construct and operate the proposed facilities.[153] The certificate was conditioned on: (i) Iroquois' completion of construction of the proposed facilities and making them available for service within ***three years*** of the date of the; (ii) Iroquois' compliance with all applicable FERC regulations under the NGA; (iii) Iroquois' compliance with the environmental conditions listed in the appendix to the order; and (iv) Iroquois' filing written statements affirming that it has executed firm service agreements for volumes and service terms equivalent to those in its precedent agreements, prior to commencing construction. The March 25, 2022 order also approved, as modified, Iroquois' proposed incremental recourse rate and incremental

[151] 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.

[152] Notice of Determination by the Chairman, *Total Gas & Power North America, Inc. et al.*, Docket No. IN12-17 (May 9, 2022).

[153] *Iroquois Gas Transmission Sys., L.P.*, 178 FERC ¶ 61,200 (2022) (*Iroquois Certificate Order*).

fuel retention percentages as the initial rates for transportation on the Enhancement by Compression Project.

- On April 18, 2022, Iroquois accepted the certificate issued in the *Iroquois Certificate Order*.
- On June 17, 2022, in accordance with the *Iroquois Certificate Order,* Iroquois submitted its Implementation Plan, documenting how it will comply with the FERC's Certificate conditions.
- The Project is targeted for a 4th quarter, 2023 in-service date.

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.[154] 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*.[155] Further, in an interesting twist, the FERC found that a December 5, 2017 "Renewed Motion for Expedited Action" filed by National Fuel Gas Supply Corporation and Empire Pipeline, Inc. (the "Companies"), in which the Companies asserted a separate basis for their claim that the NY DEC waived its authority under section 401 of the Clean Water Act ("CWA") to issue or deny a water quality certification for the Northern Access Project, served as a motion requesting a waiver determination by the FERC,[156] 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.[157] 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.[158] 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

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

[155] *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).

[156] 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).

[157] *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*").

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

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,[159] 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.[160]
- 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, [161] finding the request premature. The FERC reiterated its encouragement that pipeline applicants requesting extensions "file their requests no more than 120 days before the deadline to complete construction", so that the FERC has the relevant information available to determine whether good cause exists to grant an extension of time and whether the FERC's prior findings remain valid.[162]
- On January 28, 2022, Applicants again requested an additional extension of time, this time until December 31, 2024, to complete construction of the Project and enter service. Comments on that request were due on or before February 16, 2022. Many individual comments and protests were received. The NY DEC filed comments opposing the extension request. On March 3, 2022, National Fuel answered the NY DEC protest. The FERC requested additional environmental information on May 4, 2022 and National Fuel provided that information on May 9, 2022. The request for an extension of time remains pending before the FERC.

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

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[159] 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).

[160] *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).

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

[162] *Id.* at P 10.

Jan 25, 2021	Wholesale Market Reform
Feb 2, 2021	Transmission Planning
Feb 25, 2021	Governance Reform
Mar 18, 2021	Equity and Environmental Justice

Written comments on the topics and discussions addressed in the on the equity and environmental justice topics and discussions were, following an extension, due by May 13, 2021. Comments submitted are posted on **NewEnglandEnergyVision.com**. Recordings of the technical forums, as well as draft notices, agendas, and additional information on these sessions, are also available on the New England States' Vision Statement website (https://newenglandenergyvision.com/).

Report to the Governors. On June 29, 2021, the NESCOE Managers published their Progress Report to the New England Governors Regarding "Advancing the New England Energy Vision". The Report was further discussed at the August 5, 2021 Participants Committee meeting. View Report here.

ISO-NE Board Response. On September 23, 2021, the ISO-NE Board responded to the New England States' Vision Statement and Advancing the Vision Report. A copy of that response was included with the materials for the October 7, 2021 Participants Committee meeting and is posted on the ISO-NE website here.

XVI. Federal Courts

The following are matters of interest, including petitions for review of FERC decisions in NEPOOL-related proceedings, that are currently pending before the federal courts (unless otherwise noted, the cases are before the U.S. Court of Appeals for the District of Columbia Circuit ("DC Circuit")). An "**" following the Case No. indicates that NEPOOL has intervened or is a litigant in the appeal. The remaining matters are appeals as to which NEPOOL has no organizational interest but that may be of interest to Participants. For further information on any of these proceedings, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- ***2nd Revised Narragansett LSA Orders* (22-1108)**
  Underlying FERC *Proceeding*: ER22-707[163]
  Petitioner: Green Development
  Status: Initial Submission Scheduled

On June 15, 2022, Green Development petitioned the DC Circuit for review of the FERC's *2nd Revised Narragansett LSA Orders*.[164] On June 17, 2022, the Court directed Green Development to file a Docketing Statement, Statement of Issues, any Procedural Motions, and the underlying decisions from which the appeal arises by July 18, 2022. Appearances must also be filed by July 18, 2022. Dispositive motions, if any, and a Certified Index to the Record must be filed by August 1, 2022.

[163] *ISO New England Inc. and New England Power Co. d/b/a National Grid*, 178 FERC ¶ 61,115 (Feb. 18, 2022) ("*2nd Rev Narragansett LSA Order*"). *ISO New England Inc. and New England Power Co. d/b/a National Grid*, 179 FERC ¶ 62,035 (Apr. 18, 2022) (notice of denial of rehearing by operation of law and providing for further consideration). Together, these orders referred to as the "*2nd Revised Narragansett LSA Orders*".

[164] The 2nd Revised Narragansett LSA is a Local Service Agreement ("LSA") among New England Power, The Narragansett Electric Company ("Narragansett") and ISO-NE. The LSA reflects the construction of the new Iron Mine Hill Road Substation and related transmission modifications, and the assessment to Narragansett of a Direct Assignment Facilities Charge ("DAF Charge") associated with the facilities. The Iron Mine Hill Road Substation, a new 115 kV/34.5 kV substation (including modifications necessary to loop Narragansett's existing 115 kV H17 transmission line through the new substation) will connect to a new 34.5 kV distribution feeder, which will serve as the point of interconnection for several distributed generation projects being developed by Green Development, LLC ("Green Development"), located in North Smithfield, Rhode Island.

- **NTE CT Petition for Review of *Killingly CSO Termination Orders* (22-1027)**
  Underlying FERC Proceeding: ER22-355[165]
  Petitioner: NTE CT
  Status: Case Dismissed

On May 10, 2022, the DC Circuit granted ISO-NE's motion and dismissed NTE CT's petition for review of the FERC's orders accepting the termination of the Killingly Energy Center's CSO. In its *per curiam* order dismissing the case, the DC Circuit stated that NTE CT lack standing to challenge those orders, having not disputed that "it has defaulted on its financial assurance obligations under the []Tariff, nor []that this default provides a separate basis for terminating Killingly's [CSOs]." NTE had "not demonstrated a relationship between the challenged FERC orders and the ultimate relief sought."

- **CSC Request for Regulatory Asset Recovery of Previously-Incurred CIP IROL Costs (21-1275)**
  Underlying FERC Proceeding: ER21-2334[166]
  Petitioner: CSC
  Status: Case Dismissed

On December 30, 2021, CSC petitioned the DC Circuit Court of Appeals for review of the FERC's orders denying it authorization to establish a regulatory asset that would include all CIP-IROL Costs prudently incurred between January 1, 2016 and May 31, 2021 and to recover those costs under Schedule 17 over a five-year period. On May 17, 2022, however, CSC moved to dismiss its case. On May 31, 2022, the FERC granted CSC's unopposed motion and dismissed the case, issuing that day its mandate to the FERC.

- **Mystic ROE (21-1198; 21-1222, 21-1223, 21-1224, 22-1001, 22-1008, 22-1026) (consolidated)**
  Underlying FERC Proceeding: EL18-1639-010, -011,[167] -013[168]
  Petitioners: Mystic, CT Parties,[169] MA AG, ENECOS
  Status: Briefing Underway

As previously reported, this case was initiated when, on October 8, 2021, Mystic petitioned the DC Circuit Court of Appeals for review of the FERC's orders setting the base ROE for the Mystic COS Agreement at 9.33%. The *Mystic ROE Order* and subsequent FERC orders addressing the Mystic ROE issues have all also been appealed by various parties and consolidated under 21-1198. Docketing Statements and Statements of Issues to be Raised, and the Underlying Decision from which the various appeals arise have been filed as new dockets have been opened and then consolidated with 21-1198. As previously reported, the Certified Index to the Record was due, and filed by the FERC, on February 22, 2022. On March 10, 2022, MMWEC and NHEC filed a notice of intent to participate in support of FERC in Case Nos. 21-1198, 22-1008, and 22-1026 and in support of Petitioners in the remaining consolidated cases, and filed a statement of issues. On March 17, 2022, CT Parties moved to intervene, and those interventions were granted on May 4, 2022.

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[165] *ISO New England Inc.*, 178 FERC ¶ 61,001 (Jan. 3, 2022) ("*Killingly CSO Termination Order*") (order accepting CSO termination); *ISO New England Inc.*, 178 FERC ¶ 62,082 (Feb. 11, 2022) (notice denying *reh'g by operation of law and providing for further consideration)*; *ISO New England Inc.*, 178 FERC ¶ 61,130 (Feb. 23, 2022) (order addressing arguments raised on reh'g, sustaining results of *Killingly CSO Termination Order*). Together, these orders referred to as the "*Killingly CSO Termination Orders*".

[166] *Cross-Sound Cable Co., LLC*, 176 FERC ¶ 61,073 (Aug. 31, 2021) ("*August 31 Order*"); *Cross-Sound Cable Co., LLC*, 177 FERC ¶ 62,064 (Nov. 1, 2021) (Notice of Denial By Operation of Law of Rehearings of *August 31 Order*).

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

[168] *Constellation Mystic Power, LLC,* 178 FERC ¶ 61,116 (Feb. 18, 2022) ("*Mystic ROE Second Allegheny Order*")*; Constellation Mystic Power, LLC,* 178 FERC ¶ 62,028 (Jan. 18, 2022) ("*January 18 Notice*") (Notice of Denial By Operation of Law of Rehearings of Mystic ROE Second Allegheny Order).

[169] In this appeal, "CT Parties" are the Connecticut Public Utilities Regulatory Authority ("CT PURA"), Connecticut Department of Energy and Environmental Protection ("CT DEEP"), and the Connecticut Office of Consumer Counsel ("CT OCC").

Since the last Report, the Court established a briefing schedule that calls for the following: Mystic and State and Municipal Petitioners' Opening Briefs (August 3, 2022); Joint Brief for Intervenors in Support of Petitioners (August 17, 2022); Respondent's Brief (October 31, 2022); Briefs in support of Respondents (November 14, 2022); Reply Briefs (December 29, 2022); Joint Appendix (January 12, 2023); and Final Briefs (January 19, 2023). A date for oral argument and the composition of the merits panel will be provided at a later time.

- **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[170]
  Petitioners: Mystic (20-1343), NESCOE (20-1361, 21-1067), MA AG (20-1362), CT Parties (20-1365, 20-1368, 21-1070)
  Status: Oral Argument Held May 5, 2022; Awaiting Decision

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.[171] 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, 2021, the Court granted the interventions by MMWEC/NHEC, NESCOE, and ENECOS. Briefing was completed on February 24, 2022. Oral argument was held on May 5, 2022 before Judges Srinivasan, Henderson and Rao.

Since oral argument, on a related jurisdictional matter, the FERC moved for leave to issue its *May 2, 2022 Order* (described in Section II, ER22-1192 above). The FPA otherwise prevents the FERC, while an appeal is pending, from altering its findings or orders. In the *May 2, 2022 Order*, the FERC agreed with Mystic that, in light of changed circumstances (the spin transaction pursuant to which Exelon Corporation is no longer a Mystic Affiliate), it would be inappropriate to continue basing Mystic's capital structure on that of Exelon and set that part of the filing for hearing.[172] Accordingly, to the extent the *May 2, 2022 Order* constitutes a modification or vacatur of the capital structure ruling in the initial orders in this proceeding, the FERC sought leave to nonetheless issue the order. The FERC's motion was granted on June 10, 2022. This case remains pending before Judges Srinivasan, Henderson and Rao.

- ***CASPR* (20-1333, 21-1031) (consolidated)****
  Underlying FERC Proceeding: ER18-619[173]
  Petitioners: Sierra Club, NRDC, RENEW Northeast, and CLF
  Status: Being Held in Abeyance (until July 22, 2022)

On August 31, 2020, the Sierra Club, NRDC, RENEW Northeast, and CLF petitioned the DC Circuit Court of Appeals for review of the FERC's order accepting ISO-NE's CASPR revisions (which, under *Allegheny*, is ripe for review). On October 2, 2020, appearances, docketing statements, a statement of issues to be raised, and a statement of intent to utilize deferred joint appendix were filed. On October 19, 2020, the FERC moved to dismiss 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

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

[171] 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.

[172] *See Constellation Mystic Power, LLC*, 179 FERC ¶ 61,081, PP 24-25 (May 2, 2022).

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

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, 2021, CT Parties and MMWEC and NHEC filed statements of issues and notices that they intend to participate in support of Petitioners. On January 27, 2021, the Court ordered the parties to submit by February 26, 2021, proposed formats for the briefing of these cases. On March 24, 2021, the Court granted NEPOOL's intervention and established a briefing schedule that, as explained just below, has since been superseded.

On April 7, 2021, the Court granted Petitioners' motion to hold this matter in abeyance, pending further order of the Court. The parties were directed to file motions to govern future proceedings in these cases on or before October 22, 2021. On October 22, 2021, Petitioners Sierra Club, NRDC, Renew Northeast, Inc., and CLF moved the Court to hold this matter in abeyance until June 1, 2022. On October 25, 2021, the Court granted Petitioners' second motion to hold this matter in abeyance. The parties were directed to file motions to govern future proceedings in these cases on or before ***July 22, 2022***.

- ***Opinion 531-A*** **Compliance Filing Undo (20-1329)**
  Underlying FERC Proceeding: ER15-414[174]
  Petitioners: TOs' (CMP et al.)
  Status: Being Held in Abeyance

On August 28, 2020, the TOs[175] 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*[176] decision. On September 22, 2020, the FERC submitted an unopposed motion to hold this proceeding in abeyance for four months to allow for the Commission to "a future order on petitioners' request for rehearing of the order challenged in this appeal, and the rate proceeding in which the challenged order was issued remains ongoing before the Commission." On October 2, 2020, the Court granted the FERC's motion, and directed the parties to file motions to govern future proceedings in this case by February 2, 2021. On January 25, 2021, the FERC requested that the Court continue to hold this petition for review in abeyance for an additional three months, with parties to file motions to govern future proceedings at the end of that period. The FERC requested continued abeyance because of its intention to issue a future order on petitioners' request for rehearing of the order challenged in this appeal, and the rate proceeding in which the challenged order was issued remains ongoing before the FERC. Petitioners consented to the requested abeyance. On February 11, 2021, the Court issued an order that that this case remain in abeyance pending further order of the court. On April 21, 2021, the FERC filed an unopposed motion for continued abeyance of this case *because* the Commission intends to issue a future order on Petitioners' request for rehearing 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. Since the last Report, on April 14, 2022, 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.

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

[175] 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.

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

- **ISO-NE's Inventoried Energy Program ("IEP") Proposal (19-1224***; 19-1247; 19-1252; 19-1253)(consolidated); Underlying FERC Proceeding: ER19-1428**[177]
  Petitioners: ENECOS (Belmont et al.) (19-1224); MA AG (19-1247); NH PUC/NH OCA (19-1252); Sierra Club/UCS (19-1253)
  Status: Court Issues Decision Leaving Intact the IEP Except for the Inclusion of Nuclear, Biomass, Coal and Hydroelectric Generators.

On June 17, 2022, the DC Circuit issued a decision[178] leaving intact the FERC's June 2020 *IEP Remand Order*[179] ***except*** for the inclusion of nuclear, biomass, coal, and hydroelectric generators in ISO-NE's IEP, the inclusion of which the Court found arbitrary and capricious (because those resources were unlikely to change their behavior in response to the IEP payments). Because the Court believed "there is not substantial doubt that FERC would have adopted IEP if it had not included these resources in the first place [and] IEP can function sensibly without them", the Court found that it had the authority to sever this portion from the overall program and therefore vacated that portion of IEP from the remainder of the IEP. The Court upheld the remainder of the IEP and remanded the matter to the FERC for further proceedings consistent with its opinion.

Other Federal Court Activity of Interest

- ***Order 872* (20-72788,* 21-70113; 20-73375, 21-70113) (consol.) (9th Cir.)**
  Underlying FERC Proceeding: RM19-15[180]
  Petitioners: SEIA et al.
  Status: Oral Argument Held March 8, 2022; Awaiting Decision

On September 17, 2020, SEIA petitioned the 9th Circuit Court of Appeals for review of *Order 872*.[181] Briefing is complete and oral argument was held March 8, 2022 before Judges Nguyen, Miller and Bumatay. This matter is pending before the Court.

- **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[182]
  Petitioners: MISO TOs, Transource Energy, Dec 23 Petitioners et al.
  Status: Oral Argument Held Nov 18, 2021; Awaiting Decision

The MISO TOs, Transource and "Dec 23 Petitioners",[183] among others, have appealed *Opinion 569/569-A*. The MISO TOs' case has been consolidated with previous appeals that had been held in abeyance, with the lead case number assigned as 16-1325. Following completion of briefing, oral argument was held on November 18, 2021 before Judges Srinivasan, Katsas and Walker. This matter is pending before the Court.

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177 162 FERC ¶ 61,127 (Feb. 15, 2018) ("*Order 841*"); 167 FERC ¶ 61,154 (May 16, 2019) ("*Order 841-A*").

178 *Belmont Mun. Light Dept., et al., v. FERC*, 2022 WL 2182810 (June 17, 2022).

179 *ISO New England Inc.*, 171 FERC ¶ 61,235 (June 18, 2020) ("*IEP Remand Order*").

180 *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).

181 *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.

182 *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).

183 "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.

- **Algonquin Atlantic Bridge Project Briefing Order (21-1115*, 21-1138, 21-1153, 21-1155) (consol.); Underlying FERC Proceeding: CP16-9-012[184]**
  Petitioners: LS Power, Algonquin, INGA
  Status: Case Being Held in Abeyance Pending Disposition of Motions to Transfer First Circuit Cases to the DC Circuit

On May 3, 2021, Algonquin petitioned the DC Circuit Court of Appeals for review of the *Briefing Order* and the *April 19 Notice of Denial of Rehearings by Operation of Law*. Appearances, docketing statements and a statement of issues were due and filed June 4, 2021. Also on June 4, 2021, the FERC filed an unopposed motion to hold this proceeding in temporary abeyance, until August 2, 2021, including the fling of the certified index to the record, because "the May 3 petition for review no longer reflects the [FERC]'s latest determination in this matter." The Court granted the first abeyance motion. On November 15, 2021, the Court granted a third abeyance motion by the FERC, directing the parties to file motions to govern future proceedings by January 31, 2022. On January 31, 2022, Algonquin and INGA asked the Court to extend the abeyance by an additional 120 days (to May 31, 2022). On February 15, 2022, the Court issued an order extending the abeyance and directing the Petitioners to file motions to govern future proceedings by May 31, 2022. On May 31, 2022, Petitioners asked the Court to continue to hold this proceeding in abeyance pending the First Circuit's disposition of Algonquin's pending motions to transfer that Court's cases 20-1458 and 22-1201 (which also challenge the FERC's authorization of the "Atlantic Bridge Project").

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184 *Briefing Order*; *April 19 Notice of Denial of Rehearings by Operation of Law.*

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Status Report of Current Regulatory and Legal Proceedings as of June 17, 2022

I. Complaints/Section 206 Proceedings

II. Rate, ICR, FCA, Cost Recovery Filings

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

IV. OATT Amendments/Coordination Agreements

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Updates

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

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XII. Misc: Administrative & Rulemaking Proceedings

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XIV. Natural Gas Proceedings

XV. State Proceedings & Federal Legislative Proceedings

XVI. Federal Courts

Highlights of the 2021 Assessment of the ISO New England Markets

Presented By:

David B. Patton, Ph.D.

Potomac Economics
External Market Monitor

June 21, 2022

POTOMAC ECONOMICS

Introduction

- Potomac Economics serves as the External Market Monitor ("EMM") for the ISO-NE. In this role, we:
  - ✓ Evaluate and report on the competitive performance and operation of the wholesale markets operated by ISO-NE;
  - ✓ Identify and recommend necessary changes to existing and proposed market rules, tariff provisions and market design elements; and
  - ✓ Evaluate the mitigation by the Internal Market Monitor ("IMM").
- Our annual assessment of the ISO-NE markets complements the IMM's report, and focuses on key market areas summarized in this presentation:
  - ✓ Cross-market comparison of several key market outcomes and metrics;
  - ✓ Market issues related to out-of-market commitments for operating reserves;
  - ✓ Assessment of FCM design; and
  - ✓ Market operations on cold days.

Summary of Findings

- We find that the markets performed competitively but identify key improvements that will be increasingly important in the coming years.
- High priority recommendations to improve the performance of the markets today and facilitate large-scale entry of intermittent resources include:
  - ✓ **2012-8 & 2019-3:** Introducing co-optimized day-ahead operating reserves to reflect all system needs – and dynamically aligning real-time and day-ahead reserve products with the ISO's key local reliability needs.
  - ✓ **2020-2:** Accrediting capacity resources based on marginal reliability value.
  - ✓ **2018-7:** Modify the pay for performance rate to vary with the size of the operating reserve shortage.
  - ✓ **2021-1**: Replace the FCM with a prompt seasonal capacity market.
- These improvements are important now in order to reliably integrate the large quantities of renewable resources the New England states are requiring.
- We recommend eight other improvements would lower costs and/or improve the performance of the markets, although lower in priority to those above.

Cross-Market Comparison

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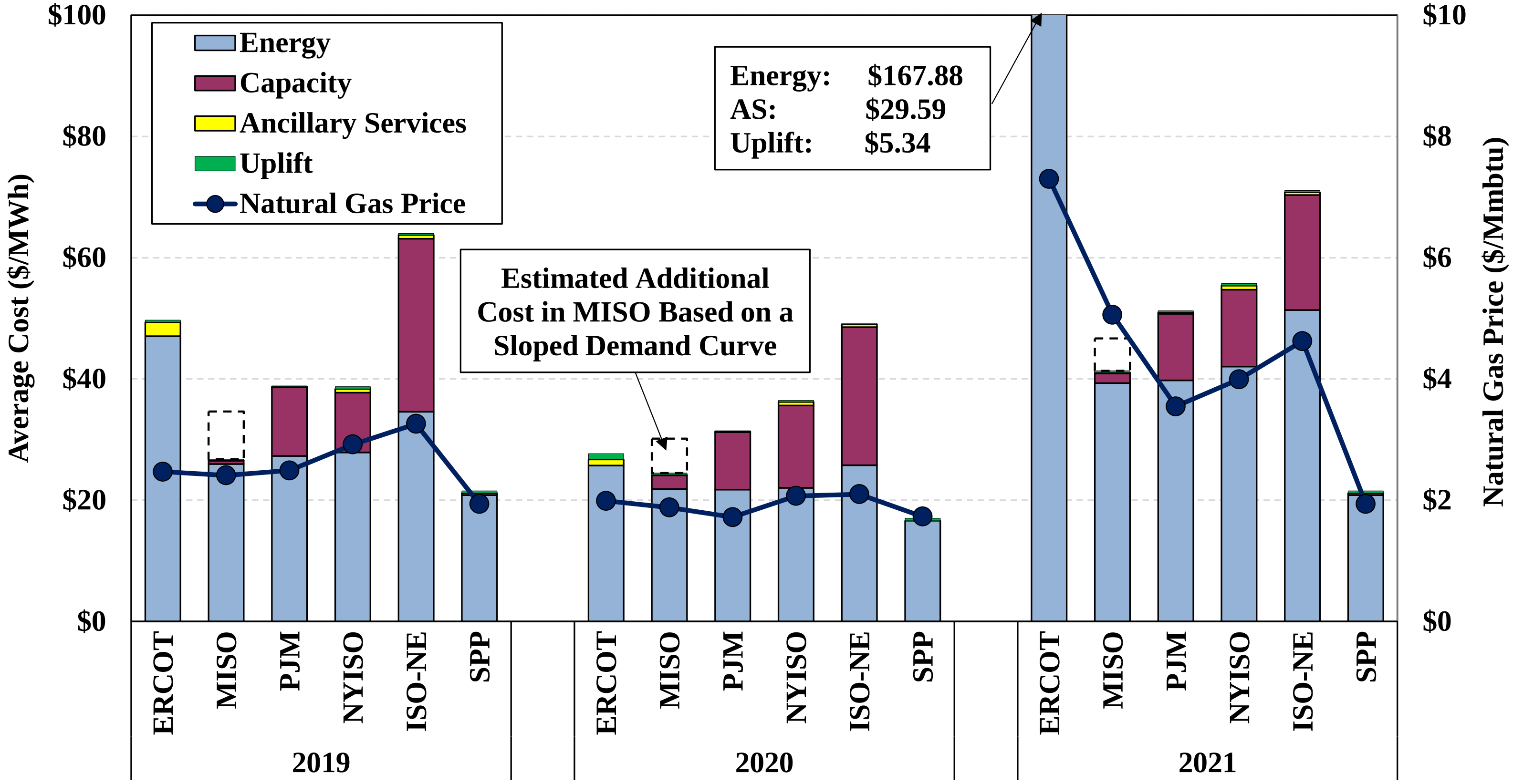
Cross-Market Comparison of Key Outcomes and Metrics

Compared to most other RTO markets, ISO-NE has:

- The highest capacity charges because of high forecasted demand ahead of the FCAs.
  - ✓ Over-forecasts are slow to correct in forward markets and place the burden of over-forecasting on consumers.
- Highest energy prices in most years due to higher gas prices.
  - ✓ ERCOT is the exception with an “energy-only” market and $9000 shortage pricing – it that led to higher energy prices in 2019 and 2021.
- Far less congestion (10%-20% of other RTOs adjusting for size) because of substantial transmission investments in the past decade.
  - ✓ However, transmission service costs more than doubled the average rates in other RTO markets.
- Less liquidity in the day-ahead market and poorer performance.
  - ✓ Caused by the inefficient allocation of costs to virtual transactions – this should be addressed with the DA reserve markets.

All-in Prices



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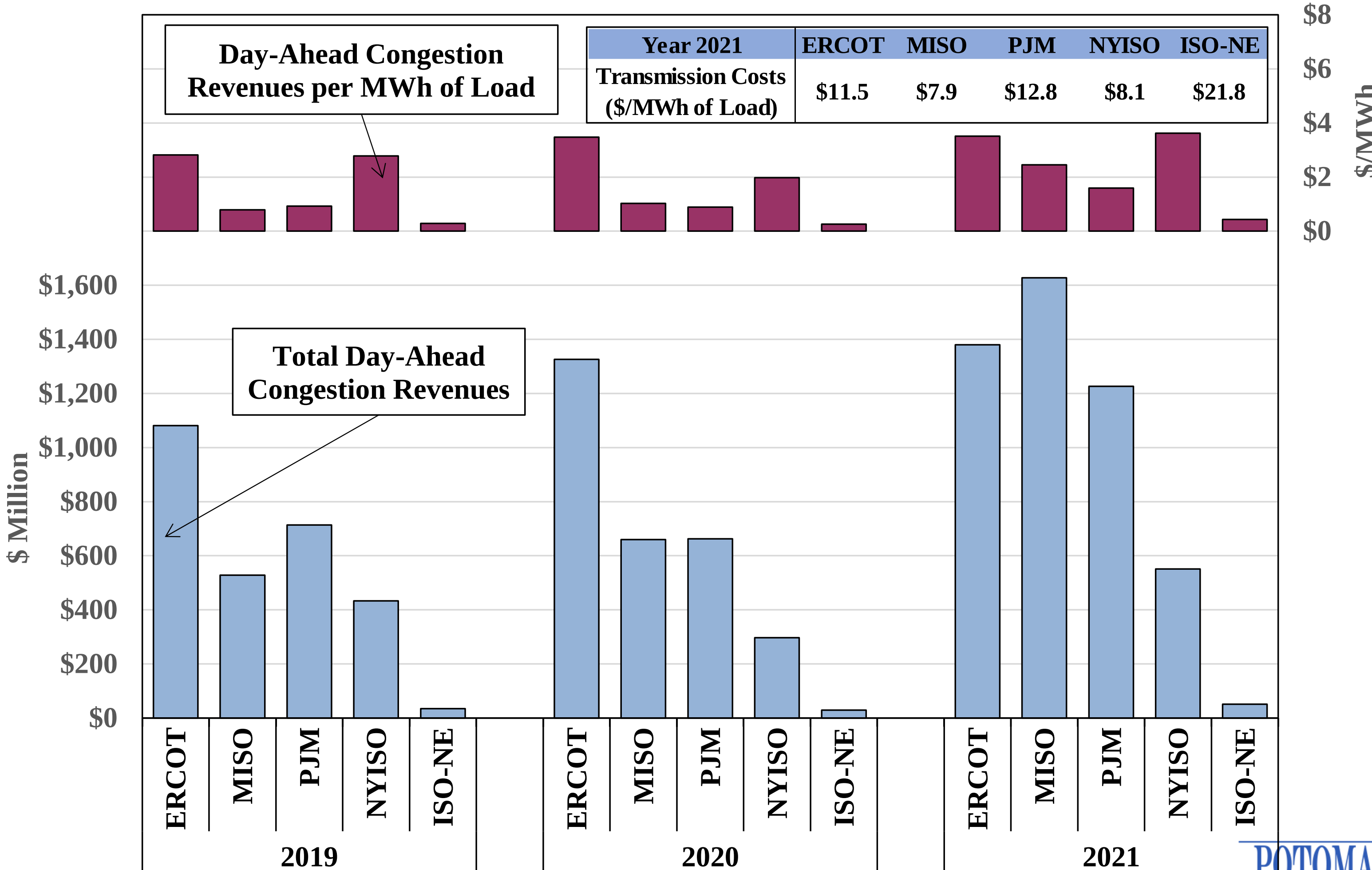
Transmission Congestion Costs



Year 2021	ERCOT	MISO	PJM	NYISO	ISO-NE
Transmission Costs ($/MWh of Load)	$11.5	$7.9	$12.8	$8.1	$21.8

See Section I.C

Virtual Transactions

Market	Year	Virtual Load		Virtual Supply		Uplift Charge Rate
		MW as a % of Load	Avg Profit	MW as a % of Load	Avg Profit	
ISO-NE	2018	2.7%	$1.10	4.5%	$2.69	$0.94
	2019	2.3%	-$1.20	4.9%	$1.26	$0.40
	2020	2.8%	$0.36	4.6%	$0.72	$0.46
	2021	2.8%	-$1.29	4.5%	$2.07	$0.53
NYISO	2021	6.2%	$0.95	9.7%	$0.73	< $0.1
MISO	2021	11.3%	$0.75	11.7%	$1.64	$0.37

OOM Commitments and Operating Reserve Markets

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OOM Commitments for Operating Reserves in the Day-Ahead Market

- Local and system-level reserve requirements cause resources to be committed out-of-market ("OOM") in the day-ahead market.
- In 2021, OOM commitments occurred in:
  - ✓ 1,250 hours for second contingency protection in local areas;
    - Accounting for 40% of day-ahead NCPC.
  - ✓ 3,400 hours for the system's 10-min spinning reserve requirement;
    - Accounting for 35% of day-ahead NCPC.
- These results demonstrate the significance of these requirements that are not priced in the day-ahead market.
  - ✓ This leads to NCPC charges and depressed market clearing prices that do not adequately reflect the value of flexible resources.
  - ✓ Ultimately, this leads to higher capacity prices and undermines incentives for investment in flexible resources.
- This underscores the need for day-ahead operating reserve markets.

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See Section III.A

Day-Ahead Commitments for 10-Minute Spinning Reserve

- Local and system-level reserve requirements (10 and 30-minute) cause resources to be committed out-of-market ("OOM") in the day-ahead market.
- In 2021, OOM commitments occurred in **3,400** hours for the system's 10-minute spinning reserve requirement – producing 35% of day-ahead NCPC.
- These commitments lower prices and which depresses incentives for investment in flexible resources.
- We estimate that pricing 10-minute spinning reserves would result in an additional revenue of up to **$18** per kW-year for units providing energy and/or system-level 10-minute spinning reserves.

Year	# Hours	Average Capacity Committed per Hour (MW)	DA NCPC (Million $)	Average Reserve Value ($/MWh)
2019	3774	580	$4.2	$2.21
2020	4054	571	$3.8	$1.68
2021	3389	514	$5.4	$1.94

Day-Ahead Commitments for Local Second Contingency Protection

- OOM commitments for second contingency protection in local areas were made in 1,250 hours – accounting for 40% of day-ahead NCPC.
- Most such OOM commitments for local needs in the past two years were for the NH-ME and NE West-to-East interfaces.
  - ✓ These local areas are not defined in ISO-NE's real-time markets and no reserve requirements are priced in its day-ahead market.
  - ✓ We estimate that pricing these needs in the day-ahead market would produce up to **$6 to $15** per kW-year of additional revenue for units in these local areas.

Year	LSCP Region	# LSCP Days	#LSCP Hours	Average LSCP Capacity per Hour (MW)	DA NCPC (Million $)	Average Uplift Rate ($/MWh)	Implied Marginal Reserve Value ($/kW-Year)
2021	**NH-to-Maine**	38	510	311	$1.6	$10.22	$8.11
	NEMA/Boston	4	42	651	$0.4	$14.31	$0.55
	Lw. SEMA & East RI	9	61	244	$0.1	$7.01	$1.05
	NE West-to-East	52	683	639	$3.5	$8.07	$6.55

OOM Commitments and Reserve Markets

Key Recommendations:

- These results demonstrate the significance of these requirements that are not priced in the day-ahead market.
  - ✓ This leads to NCPC charges and depressed market clearing prices that do not adequately reflect the value of flexible resources.
  - ✓ Ultimately, this leads to higher capacity prices and undermines incentives for investment in flexible resources.
- To address these concerns, we make two key recommendations:
  - ✓ Introduce co-optimized operating reserves in the day-ahead market reflecting all system needs. (Recommendation #2012-8)
  - ✓ Dynamically define a full set of local operating reserve requirements in the day-ahead and real-time markets. (Recommendation #2019-3)
    - – Reserve constraints should be flexible and applied when a need is recognized without tariff changes – analogous to activating at transmission constraint in the energy market.

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Market Operations On Cold Days

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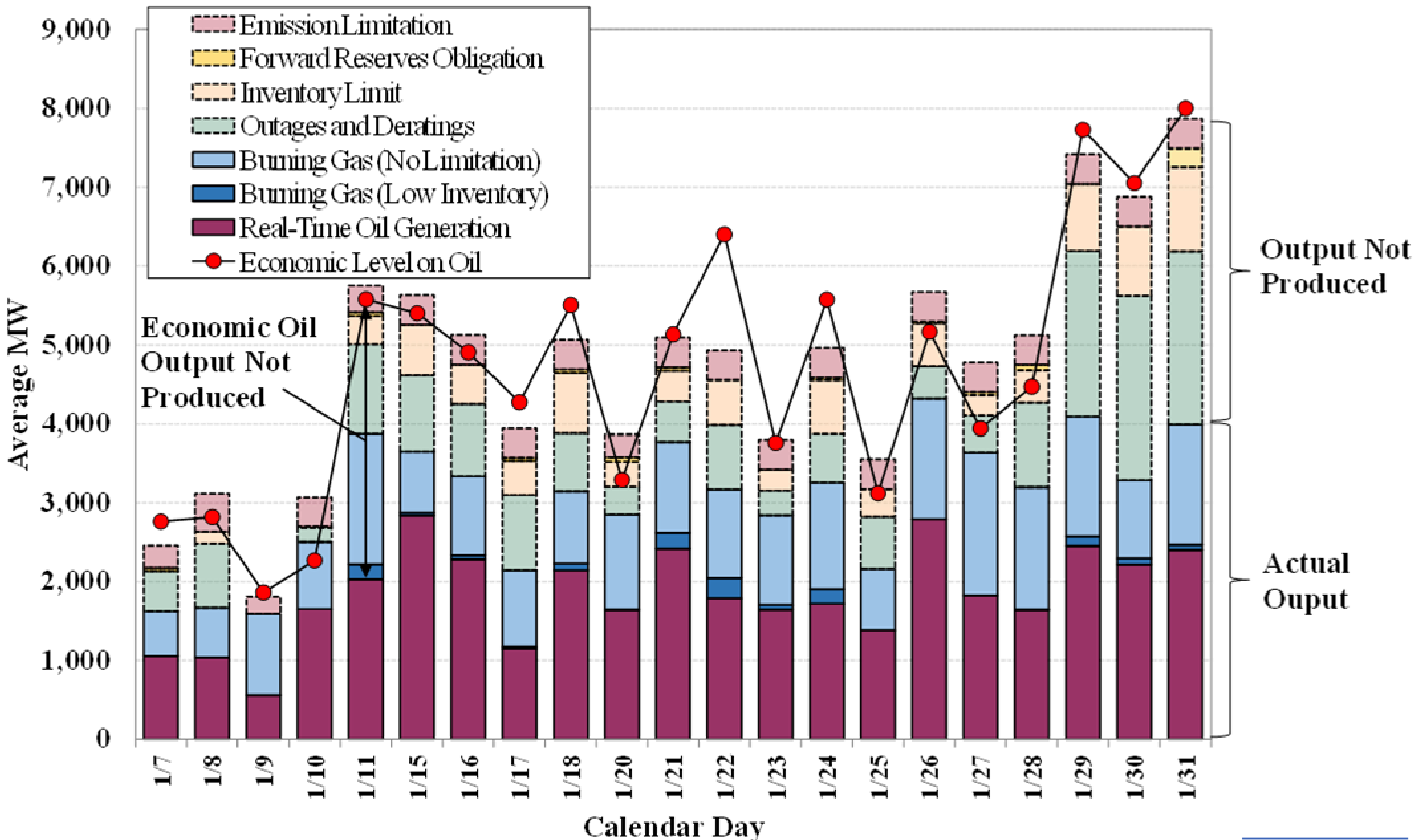
Market Operations on Cold Days

- New England has become increasingly reliant on natural gas and vulnerable to disruptions in fuel supplies – important for the day-ahead and real-time markets to facilitate efficient fuel burn decisions.
  - ✓ Hence, our report evaluates the performance of the market during cold conditions and tight gas supply conditions in January 2022.
- Our analysis of the output we estimate would have been economic to produce from oil shows:
  - ✓ This potentially economic output rose as natural gas prices increased, but only 41 percent was produced from oil.
  - ✓ 27 percent was produced from gas on units with favorable gas costs, operational considerations, or inventory or emissions limitations.
  - ✓ 32 percent was not produced because it was unavailable because of:
    - – Equipment limitations and/or air permit restrictions; and
    - – Forced outages and deratings, inventory limitations, and emission rate limitations.

Utilization of Oil-Fired and Dual-Fuel Capacity Cold Days in January 2022



Market Operations on Cold Days

- The analysis of the markets' performance in January 2022 demonstrates the following.
  - ✓ Generators do respond to the economic signals provided by the fuel markets and electricity markets.
  - ✓ It underscores that producing efficient day-ahead and real-time energy and ancillary services prices is essential.
  - ✓ This response by generators is not always easy to predict because they must consider an array of factors and limitations in making fuel procurement and burn decisions.
  - ✓ Real-time gas availability and cost can be uncertain, which will affect generators' fuel burn decisions, particularly under tight conditions.

Assessment of Forward Capacity Market

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See Section IV

Evaluation of Capacity Accreditation Rules

- Resources that provide the same reliability benefits should be compensated the same.
  - ✓ In the capacity market, the relevant benefit is resource adequacy, measured as reduction in loss-of-load expectation (LOLE) or in expected unserved energy (EUE).
  - ✓ Resources that are more likely to be available in critical hours when capacity is needed provide more reliability value.
- Current accreditation methods over-value several resource types relative to their marginal impact on reliability.
  - ✓ Provides inefficient incentives to invest or retire.
  - ✓ May affect reliability if resources are over-valued when determining the ICR.

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See Section IV.A

Current Resource Accreditation Issues

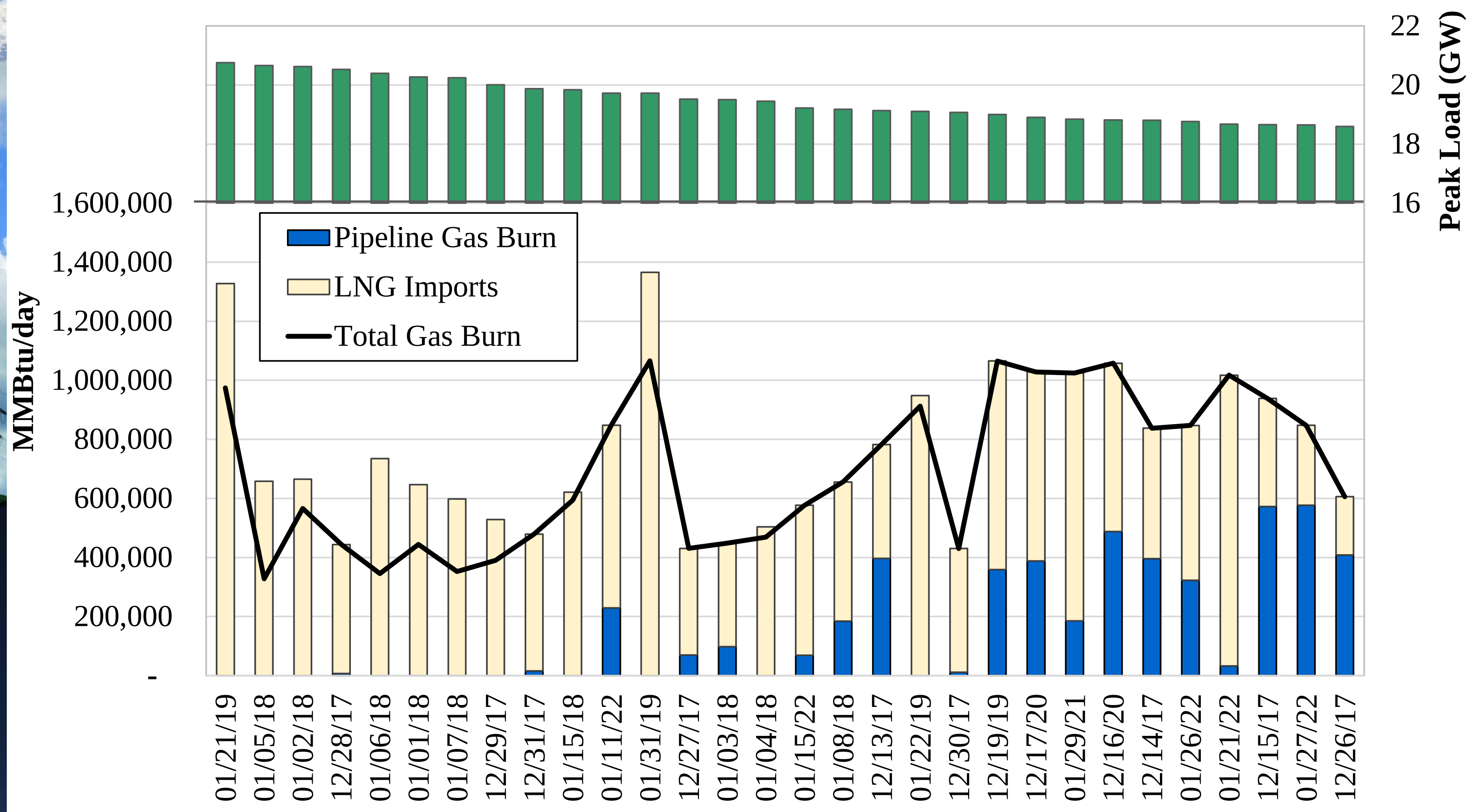
- *Intermittent Generation & Energy Limited Resources* – The reliability values of these resources fall as their penetration grows because their availability is correlated with similar units.
- *Low Flexibility* – Units with long startup times that operate infrequently provide less reliability value than flexible units.
  - ✓ If not already committed, it may be unable to start fast enough to provide output during most critical hours.
- *Large Resources* – Large units provide less reliability benefit than multiple smaller units with the same total capacity, because multiple units are less likely to be lost all at once.
- *Pipeline Gas-Dependence* – Units with shared fuel supply and no backup provide less reliability because they could be lost in a single contingency.

Problems with Current Accreditation Methods: Pipeline Gas Dependence

- The following two figures analyze the availability of pipeline-gas dependent generation during cold winter conditions.
- The figures show the correlation between winter load and the availability of pipeline gas.
  - ✓ Under cold conditions, the demand of firm gas customers (e.g., local distribution companies or LDCs) rises to more than the pipeline delivery capability.
  - ✓ Hence, the ability of gas-only generators to acquire fuel depends entirely on LNG injections.
  - ✓ Most LNG is procured by LDCs.
- These cold conditions, although infrequent, are critical because most of the reliability risk in the winter occurs during these conditions.

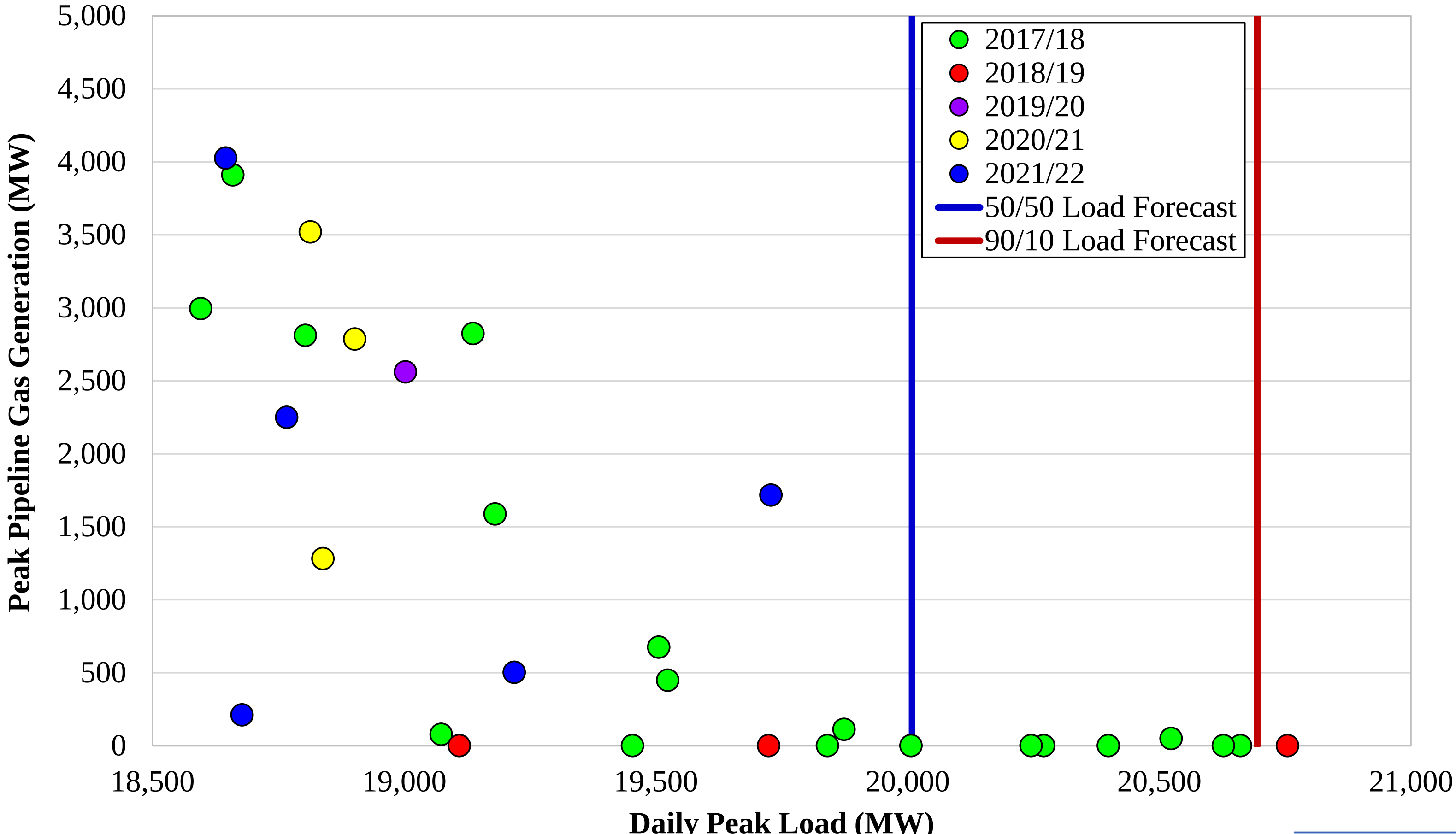
See Section IV.B

Power Plant Gas and LNG Consumption on High Load Winter Days (2017-2022)



POTOMAC ECONOMICS

Winter Peak Load vs. Pipeline Gas Generation 2017 - 2022



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Problems with Current Accreditation Methods: Pipeline Gas Dependence

- The following figure shows how reliability and accreditation is affected as New England's reliance on gas-only generation increases.
  - ✓ The x-axis is the amount of gas-only capacity (summer capability) the system is relying on at criteria.
  - ✓ The bottom panel shows the portion of the EUE that occurs in the winter.
  - ✓ The top panel shows the marginal value of the non-firm gas-only units as measured by the "marginal reliability improvement" (MRI) metric and the "average effective load carry capability" (ELCC).
- This figure shows that as reliance on non-firm gas resources increases:
  - ✓ Reliability risks shift almost entirely to the winter.
  - ✓ The marginal value of non-firm gas resources falls to zero as the marginal resources will not be able to schedule fuel.
  - ✓ Accrediting resources to reflect this will provide strong incentives for some suppliers to procure firm fuel. This increases their value of the non-firm resources.
  - ✓ It is critical to accredit all resources based on their marginal value.

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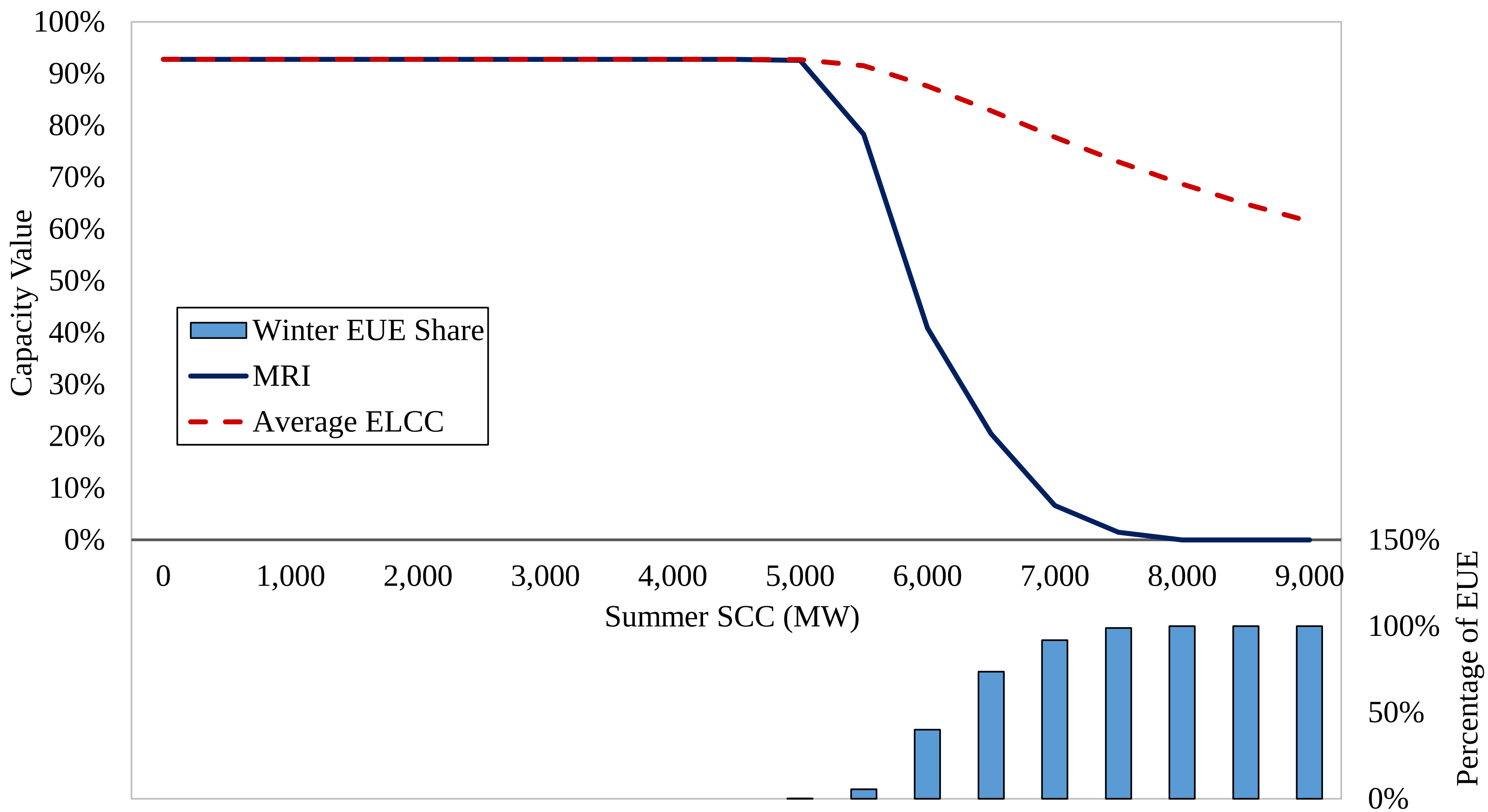
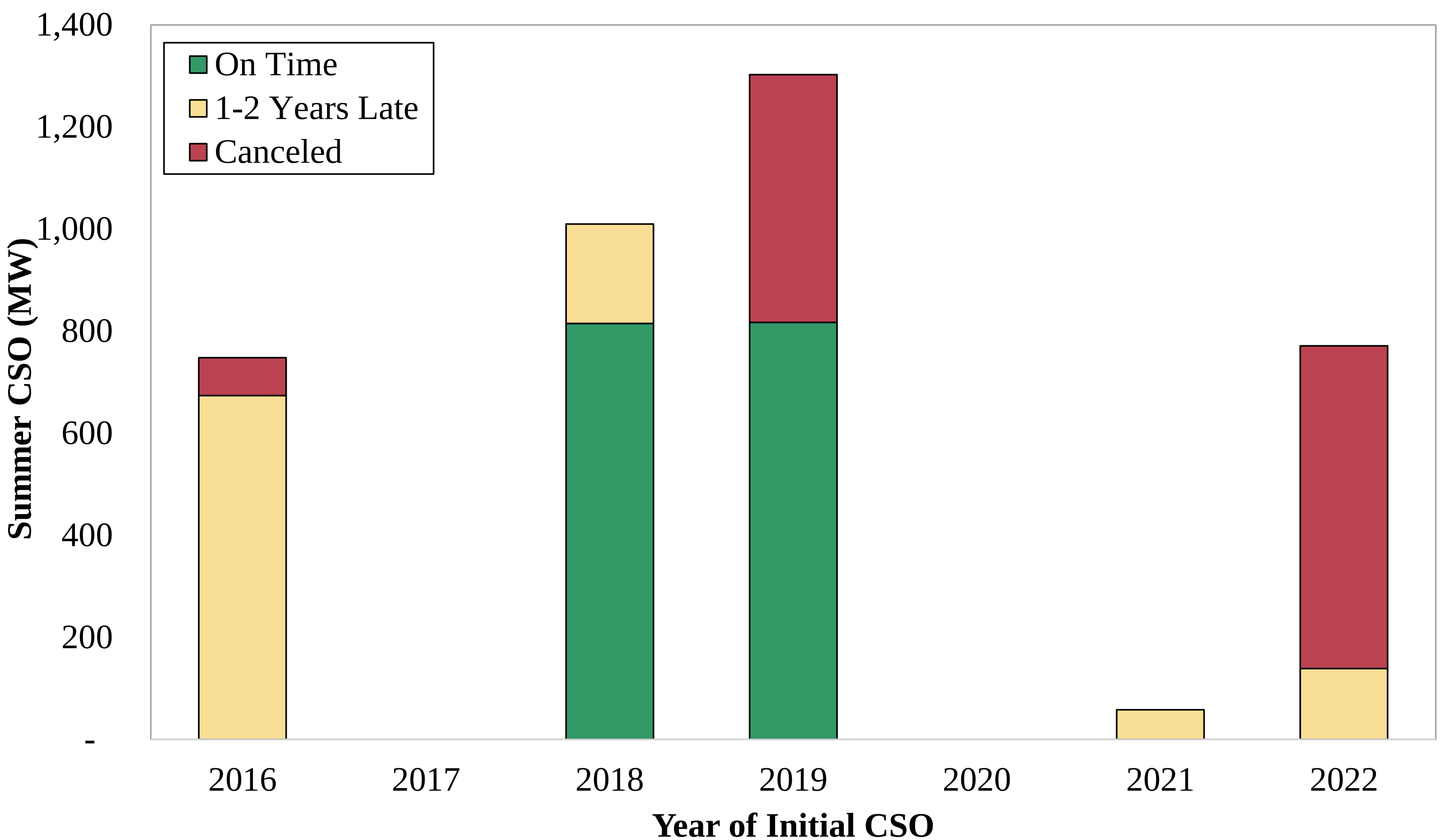
Capacity Value Curve for Non-Firm Pipeline Gas Generators



Concerns with the Forward Capacity Market

- FCM has had a dubious track record of coordinating timely entry of new resources as shown in the next figure.
  - ✓ The timing of new entry is uncertain and being compelled to sell capacity forward can expose developers to substantial risk.
  - ✓ The outcome cannot be pivotal in the decision to enter since almost all of the economic value of a resource occurs after the initial planning year.
  - ✓ The three-year forward term of the FCA is not aligned with development timeframes for a growing share of projects in ISO-NE.
    - – The FCM inhibits resources with fast development timeframes from receiving capacity payments as soon as they are able to support reliability.
- The FCM also creates significant financial risks for existing older generators.
  - ✓ Retirement of older units is often prompted by unforeseen equipment failure that is not economic to repair.
  - ✓ Such units must accept a capacity obligation that ends more than four years after the FCA, which creates substantial risk for the supplier.
  - ✓ This risk can cause older resources to retire prematurely.

New Generation Projects with Initial CSO > 50 MW



POTOMAC ECONOMICS

Concerns with the Forward Capacity Market

- The FCM is more prone to misalignment with the planning models.
- Critical planning assumptions that are much more uncertain include:
  - ✓ The expected resource mix – this is a key assumption because it affects the system needs and the accreditation of the resources.
  - ✓ Forecasted load – these errors are larger and take much longer to correct. When actual trends deviate, adjustment will not begin for three years.
- Decisions to contract for firm fuel are not optimal to make three years in advance.
  - ✓ Such decisions should affect resources' accreditation in the future.
  - ✓ Most fuel contracting decisions occur months ahead of the season, rather than years ahead.

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See Section IV

Forward Capacity Market Recommendations

- To address these concerns, we recommend two key changes:
  - ✓ Implement *a seasonal market* to reflect the shift of reliability needs to the winter and seasonal accreditation differences for gas-only resources.
  - ✓ Shift the timeframe of the capacity auction from three-years ahead to a *prompt timeframe* (one to three months ahead of the planning period).
- These reforms would provide better long-term incentives governing:
  - ✓ Winter reliability needs and fuel contracting
  - ✓ Efficient investment and retirement decisions
- We also recommend the following additional capacity market changes:
  - ✓ Reflect the increased risk from eliminating MOPR in the CONE value.
  - ✓ Accredit all capacity resources based on their marginal reliability value.
  - ✓ Replace the descending clock auction format with a sealed bid auction.
  - ✓ Introduce a reasonable slope to the performance payment rate to allow it to vary efficiently with the depth of the reserve shortage.

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Full List of Recommendations

List of Recommendations

Recommendation Number and Description		High Benefit[1]	Feasible in ST[2]	Report Reference
Reliability Commitments and NCPC Allocation				
2010-4	Modify allocation of "Economic" NCPC charges to make it consistent with a "cost causation" principle.		✓	2018 Report Section III
2020-1	Consider allowing firm energy imports from neighboring areas to satisfy local second contingency requirements.		✓	Section III.B
2014-5	Utilize the lowest-cost configuration for multi-unit generators when committed for local reliability.		✓	Section III.B
Reserve Markets				
2012-8	Introduce co-optimized operating reserves in the day-ahead market reflecting forecasted system needs.	✓		Section III.A
2019-3	Dynamically define a full set of local operating reserve requirements in the day-ahead and real-time markets.	✓		Section III.B
2014-7	Eliminate the forward reserve market.		✓	2014 Report Section I.B.

Notes: 1. *High Benefit*: Will likely produce considerable efficiency benefits.
2. *Feasible in Short Term*: Complexity and software modifications are likely limited.

Recommendation Number and Description		High Benefit[1]	Feasible in ST[2]	Report Reference
External Transactions				
2016-5	Pursue improvements to the price forecasting or other reforms to improve Coordinated Transaction Scheduling.			2017 Report Section VI.C
Capacity Market				
2015-7	Replace the descending clock auction with a sealed-bid auction to improve competition in the FCA.			2017 Report Section IV.A
2018-7	Modify the PPR to rise with the reserve shortage level, and not implement the remaining planned increase in the payment rate.	✓	✓	2019 Report Section V
2020-2	Improve capacity accreditation by: a) Accrediting all resources consistent with their marginal reliability value, and b) modify the planning model to accurately estimate marginal reliability values.	✓		Section IV.A-B
2020-3	Account for energy efficiency as a reduction in load instead of as a supply resource in the FCM.		✓	2020 Report Section V
2021-1	Replace the forward capacity market with a prompt seasonal capacity market.	✓		Section IV.C
2021-2	Include the effects of MOPR elimination on investment risk when establishing the net CONE for the demand curve.		✓	Section IV.D

POTOMAC ECONOMICS

2021 Assessment of the ISO New England Electricity Markets

Prepared By:

POTOMAC ECONOMICS

External Market Monitor for ISO-NE

June 2022

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PREFACE

Potomac Economics serves as the External Market Monitor for ISO-NE. In this role, we are responsible for evaluating the competitive performance, design, and operation of the wholesale electricity markets operated by ISO-NE.[1] In this assessment, we provide our annual evaluation of the ISO's markets for 2021 and our recommendations for future improvements. This report complements the Annual Markets Report, which provides the Internal Market Monitor's evaluation of the market outcomes in 2021.

We wish to express our appreciation to the Internal Market Monitor and other staff of the ISO for providing the data and information necessary to produce this report.

The principal authors of this report are:

David B. Patton, Ph.D.
Pallas LeeVanSchaick, Ph.D.
Jie Chen, Ph.D., and
Joseph Coscia

1 The functions of the External Market Monitor are listed in Appendix III.A.2.2 of "Market Rule 1."

EXECUTIVE SUMMARY

ISO-NE operates competitive wholesale markets for energy, operating reserves, regulation, financial transmission rights (FTRs), and capacity to satisfy the electricity needs of New England. These markets provide substantial benefits to the region by coordinating the commitment and dispatch of the region's resources to ensure that the lowest-cost supplies are used to reliably satisfy demand in the short-term. At the same time, the markets establish transparent, efficient price signals that govern long-term investment and retirement decisions.

ISO-NE's Internal Market Monitor (IMM) produces an annual report that provides an excellent summary and discussion of the market outcomes during the year, which shows:[2]

- Real time energy prices averaged $44.84 per MWh at the New England Hub, up 92 percent from the historic lows in 2020. The primary driver was the 120 percent increase in natural gas prices from 2020 to 2021. This correlation is consistent with our finding that the market performed competitively because energy offers should track input costs in a competitive market.
- Average load rose roughly 2 percent in 2021, reflecting more frequent peaking conditions in the winter and summer months because of weather and dissipation of the effects of the COVID-19 pandemic. Nonetheless, load levels have been on a downward trend in recent years because of continued energy efficiency and behind-the-meter solar generation.
- The market was never short of operating reserves in 2021 because of the availability of sufficient surplus capacity, so no Pay-for-Performance (PFP) events occurred.
- The capacity compensation rate was $5.30 per kW-month in the 2020/21 Capacity Commitment Period (CCP) and $4.63 per kW-month in the 2021/22 CCP.
  - These relatively high levels reflect that the peak load forecasts for the FCAs held in 2017 and 2018 were significantly higher than the actual peak loads in 2020 and 2021.
  - Capacity prices will fall through FCA 14 (2023/24 CCP) to $2 per kW-month because of declining load forecasts and the retention of the Mystic CCs, before rising modestly to roughly $2.60 per kW-month in FCAs 15 and16 (the 2024/25 and 2025/26 CCPs) after the Mystic cost-of-service agreement ends.

The IMM report provides detailed discussion of these trends and other market results in 2021. This report complements the IMM report, comparing key market outcomes with other RTO markets, assessing the competitive performance of the markets, and evaluating market design issues. This report addresses long-term economic incentives, out-of-market commitments, winter operations and reliability, and capacity market design and accreditation.

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[2] See ISO New England's Internal Market Monitor 2021 Annual Markets Report, available at https://www.iso-ne.com/markets-operations/market-monitoring-mitigation/internal-monitor.

Cross-Market Comparison of Key Market Outcomes

ISO New England faces very different challenges than many other RTOs, which affect the structure and performance of its markets. In particular, ISO-NE is located at the end of a number of interstate pipelines whose aggregate capability to deliver gas to the region's gas utilities and gas-fired generators is limited. It also operates a network that is far less congested than most other RTO's, which affects its competitive performance, operating requirements, and reliability.

We compare several key market outcomes in the ISO-NE markets to comparable outcomes and metrics in other RTO markets in Sections 0 of this report and find that:

Energy Prices ISO-NE generally exhibited the highest average energy prices of the RTO markets in recent years because of its higher natural gas prices. However, ERCOT, which operates an "energy-only" market with shortage pricing as high as $9,000 per MWh, averaged higher prices in 2021 because of unusually high energy prices during several days of shortages in February 2021.

Capacity Prices Capacity prices in New England were substantially higher than in the other RTOs. Lower capacity prices in other markets have generally been due to higher surpluses in those areas and MISO's poor market design. Additionally, over-forecasted peak loads and associated capacity requirements can only be slowly addressed (over three years) in ISO-NEs forward capacity market.

Congestion ISO-NE experiences far less congestion than other RTOs. As per MWh of load, the average congestion cost in New England was less than $0.38 per MWh – roughly 10 to 20 percent of the average congestion levels in other RTO markets. This reflects that large transmission investments have been made over the past decade, resulting in transmission costs of nearly $22 per MWh in 2021 – more than double the average rates in other RTO markets.

Transmission investments in ISO-NE have been made primarily to satisfy relatively aggressive local reliability planning criteria, while the primary reasons for transmission expansion in ERCOT, MISO, and the NYISO have been to increase the deliverability of renewable generation to consumers.

Uplift Costs ISO-NE generally incurs more market-wide uplift costs, adjusted for its size, than MISO and the NYISO. The higher costs arise because: (a) ISO-NE's fuel costs tend to be higher, (b) it does not have day-ahead ancillary services markets to coordinate and price its operating reserve requirements, and (c) ISO-NE makes real-time NCPC payments to resources under a wider range of circumstances than do MISO and the NYISO. Introduction of day-ahead operating reserve markets will significantly reduce these costs.

Virtual Trading	The virtual trading levels in ISO-NE have been 30 to 40 percent of the levels in NYISO and MISO primarily because ISO-NE over-allocates real-time NCPC charges to virtual transactions and other real-time deviations. (See Recommendation #2010-4) It is important to address this issue since virtual trading can play an important role in aligning the day-ahead and real-time market outcomes as the system's generation portfolio transitions to a much heavier reliance on intermittent renewable resources.
External Transactions	The CTS process between New England and New York has performed far better than the CTS processes between PJM and the NYISO and between PJM and MISO. ISO-NE's process with the NYISO exhibits much higher bid liquidity, largely because of the RTOs' decision not to impose charges on CTS transactions and better price forecasting. However, forecast errors still limit the potential benefits of CTS, so the ISO should continue to improve the forecasts or consider using real-time prices. (See Recommendation #2016-5)
Shortage Pricing	ISO-NE has the most aggressive shortage pricing in the country, most of which is settled through the PFP framework rather than the energy market. The PFP framework reduces the potential financial risks in several key ways, but generates outsized risks associated with modest shortages that generally do not raise substantial reliability concerns. We recommend ISO-NE address this by varying the penalty rate with the size of the shortage and capping the penalty rate based on a reasonable VOLL. (See Recommendation #2018-7)

Competitive Assessment

Based on our evaluation of the ISO-NE's wholesale electricity markets contained in Section II of this report, we find that the markets performed competitively in 2021. Our pivotal supplier analysis suggests that structural market power concerns diminished noticeably in Boston and New England since 2018 because of:

- The entry of more than 2.5 GW of generation;
- Transmission upgrades in Boston; and
- Falling load levels due to combined effects of continued energy efficiency improvements, growth of behind-the-meter solar generation, and the effects of the COVID-19 pandemic.

Our analyses of potential economic and physical withholding also indicates that the markets performed competitively with little evidence of significant market power abuses or manipulation in 2021. We find that the market power mitigation has generally been effective in preventing the exercise of market power in the New England markets, and was generally implemented consistent with Appendix A of Market Rule 1. The automated mitigation process helps ensure the competitiveness of market outcomes by mitigating attempts to exercise market power in the real-time market software before it can affect the market outcomes.

The only area where the mitigation measures may not have been fully effective is in their application to resources frequently committed for local reliability. Although the mitigation thresholds are tight, suppliers have the incentive to operate in a higher-cost mode and receive higher NCPC payments as a result. In 2021, 46 percent of resources committed for local reliability were committed in a multi-turbine combined cycle configuration when a single-turbine configuration would likely have been adequate to satisfy the reliability need. In addition to inflating the NCPC costs, this over-commitment depresses prices in key load pockets and undermines incentives for flexible resources to be available. Hence, we recommend the ISO consider tariff changes as needed to expand its authority to address this concern. (See Recommendation #2014-5)

Out-of-Market Commitments and Operating Reserve Markets

The ISO commits resources within the day-ahead market scheduling process to satisfy two types of reliability requirements:

- Ensure the ISO is able to reposition the system in certain local areas in response to the second largest contingency after the first largest contingency has occurred; and
- Satisfy system-level operating reserve requirements in the day-ahead market.

However, these local and system-level reserves are not procured or priced in the day-ahead market. Consequently, the price of energy is often understated when such commitments occur because the costs of satisfying these reserve requirements are not reflected in the prices. Procuring and pricing these requirements in the day-ahead market would result in substantial additional net revenues, especially for flexible resources such as fast-starting peaking units and battery storage units that will be helpful for integrating intermittent renewable generation.

In Section III of this report, we evaluate supplemental commitment by the ISO to maintain reliability, the resulting NCPC charges, and impacts on market incentives. Our assessment of day-ahead reliability commitments in 2021 showed they occurred in more than half the hours:

- Commitment for local second contingency protection occurred in roughly 1,250 hours and accounted for 40 percent of the day-ahead NCPC.
- Commitments to satisfy the system's 10-minute spinning reserve requirement occurred in roughly 3,400 hours and accounted for 35 percent of the day-ahead NCPC.

The resources that contribute to satisfying these requirements are generally undervalued as the cost of scheduling operating reserves is not reflected efficiently in either reserve prices or energy prices. We estimate that pricing these requirements in the day-ahead market would result in an additional revenue of:

- Up to \$6 to \$15 per kW-year for units in the areas with local second contingency protection requirements; and

- Up to $18 per kW-year for units providing energy and/or system-level 10-minute spinning reserves.

Given that the annualized net cost of entry of a new peaking resource is typically estimated to be $80 to $100 per kW-year, pricing these requirements would help incent investment in new and existing resources with flexible characteristics in key locations.

In addition, we continue to find that out-of-market commitment and NCPC costs are inflated because: (a) the ISO is often compelled to start combined-cycle resources in a multi-turbine configuration when its reliability needs could have been satisfied by starting them in a single-turbine configuration; and (b) the ISO does not allow firm energy imports to be counted towards satisfying local second contingency needs that determine local reserve requirements.

Given these findings, we make five recommendations to improve the scheduling and pricing of energy and operating reserves. We recommend that the ISO:

- Introduce co-optimized operating reserves in the day-ahead market that reflect the ISO's operational needs, such as the Flexible Response Services ("FRS") proposed under its *Day-Ahead Ancillary Services Improvements* project (See Recommendation #2012-8)
- Consider approaches that would allow it to dynamically define new reserve zones as second contingency protection requirements arise in different areas. (See Recommendation #2019-3)
- Expand its authority to commit combined-cycle units in a single-turbine configuration when that will satisfy its reliability need. (See Recommendation #2014-5)
- Consider allowing firm energy imports from neighboring areas to satisfy local second contingency requirements. (See Recommendation #2020-1)
- Eliminate the Forward Reserve Market, which has resulted in inefficient economic signals and market costs. Implementation of day-ahead reserve markets further decreases any potential value this market may have offered. (See Recommendation #2014-7)

Generator Operations during January 2022 Cold Weather

New England has become vulnerable to natural gas supply limitations during cold weather conditions over the past decade with the retirement of older oil-fired, dual-fuel, and nuclear generation. ISO-NE is considering capacity market enhancements to procure resources needed to maintain reliability during periods of extreme natural gas scarcity. Nonetheless, ISO will continue to rely on its energy and ancillary services markets to coordinate the efficient commitment and dispatch of all of its resources, and to provide efficient incentives to procure fuel and perform reliably. Conditions in January 2022 provided an opportunity to evaluate the market's performance cold weather conditions and the incentives they provide to be available.

The report shows that natural gas pipeline limitations led day-ahead gas prices to rise near the delivered prices of ultra-low sulfur diesel ("ULSD") as many generators burned a mix of oil and gas during the period. Although gas prices were relatively high in January, they never rose far above delivered ULSD prices because large amounts of gas were available throughout the month. No day averaged less than 3.5 GW of gas-fired output compared to conditions in the Winter of 2017/18 when pipeline gas-fired generation fell to as little as 1.5 GW on day and gas prices exceeded $100 per MMbtu. Oil-fired generation was modest, although it rose as high as 3 GW on the highest-load days when the spread between gas and oil prices was highest.

Economic Oil Utilization. Although oil-fired generation increased as it became more economic than natural gas, we found that it averaged just 41 percent of the amount we estimate would have been economic in January. Actual oil-fired output averaged 41 percent of the capacity that we estimate would have been economic to burn fuel oil on these days. In some cases, these resources burned natural gas instead and in other cases they did not run as we explain below.

27 percent of the economic oil-fired output was produced by burning natural gas because:

- *Favorable Gas Costs*. Most of the output from gas (84 percent) came from either baseloaded cogeneration plants or plants that are situated favorably upstream of key pipeline constraints that often have better access to gas at potentially lower prices.
- *Operational Benefits*. The choice of fuel may affect the operational characteristics of the generator. For example, burning oil may restrict access to duct-firing ranges on a combined-cycle unit and lower its potential output.
- *Oil Inventory Management*. Generators with limited oil inventories may burn natural gas to conserve their oil, although this was not likely a significant factor during this period.
- *Total Emissions Limits*. Air permit restrictions may limit a generator's number of oil-fired hours per year, which was also not likely binding in January 2022.

The remaining 32 percent of estimated economic oil-fired output was not produced because of:

- *Forced outages and deratings*. Led an average of 860 MW to be unavailable over the period and over 2.3 GW from January 29 to 31.
- *Inventory-limited units*. Accounted for an estimated 450 MW of unutilized capacity.
- *Emission rate limitations*. Accounted for 360 MW from generators that had difficulty keeping their emissions within the tolerances required by their air permits.

Economic Gas Utilization. Our evaluation of actual gas burn showed a relatively weak relationship between the estimated production costs of gas-fired resources and the generation costs implied by their actual operation. On most days, actual gas-fired generation was *lower* than our estimated economic level (by almost 30 percent on average) primarily because additional gas burn would either have been limited by pipeline restrictions or because additional gas would only have been available at a premium. However, on a substantial number of days, actual gas-fired generation was much *higher* than our estimated economic level because gas often became available at a lower price intraday than was available day-ahead. This happens when actual consumption by core natural gas demand is lower than LDCs' forecasts, making more gas available to generators after the timely window has closed.

Overall, this section of the report demonstrates that generators do respond to the economic signals provided by the fuel markets and electricity markets. This underscores that producing efficient day-ahead and real-time energy and ancillary services prices is of paramount importance. This response by generators is not always easy to predict because they must consider an array of factors and limitations in making fuel procurement and burn decisions. Real-time gas availability and cost can be highly uncertain, which will affect generators' fuel burn decisions, particularly under tight conditions.

In the longer-term, efficient energy and ancillary service prices along with the incentives provided by the capacity market reforms discussed below should motivate generators to efficient fuel procurement and inventory decisions in advance of the winter season. This will be increasingly important as maintaining reliability in the winter season becomes much more challenging for the ISO.

Assessment of Forward Capacity Market Design

The capacity market is the primary market mechanism for satisfying ISO-NE's requirement to ensure a minimum level of reliability (i.e., load shedding no more than 1 day every 10 years). It will become more complex and challenging to do this efficiently because of the expected changes in New England's power sector including:

- Large-scale entry of state-sponsored resources that receive a combination of wholesale market revenues and out-of-market revenues,
- Growing reliance on intermittent and energy-limited resources with complex availability characteristics, and
- Increased awareness of limitations faced by the generation fleet during extreme weather, especially in winter months.

This report highlights several changes needed to ensure that the capacity market sends efficient signals to attract and retain investment needed for reliability under these new circumstances.

Resource Adequacy Modeling and Efficient Capacity Accreditation

Capacity accreditation is the number of megawatts a resource may sell in the capacity market. An efficient capacity market provides the same level of compensation to all resources that provide comparable reliability benefits.

A resource's capacity credit should reflect its marginal reliability value, which is how much system reliability would change if an increment of that resource type were to enter the market or retire. Marginal capacity accreditation provides efficient incentives to invest in resources that complement each other (such as pairing renewables with storage) and retire surplus resources that provide little reliability value.

Current capacity accreditation methods over-value several resource types, including:

- Intermittent Resources – Qualified capacity of intermittent resources such as wind and solar is based on their median output at certain times of the day and doesn't consider correlation of resources' output which will affect the timing of reliability needs.
- Energy Storage – These are accredited up to 100 percent of their installed capacity if they can discharge for at least two hours. This substantially over-compensates low-duration batteries relative to their reliability value.
- Pipeline Gas-Dependence – Generators that rely on pipeline gas and lack backup fuel are accredited as if fuel is always available to them, but in practice these generators have limited availability during the winter.
- Large Resources or Resources with Correlated Outages – Large individual units provide reduced reliability value because all their capacity can be lost in a single outage, but this is not reflected in their capacity credit. Likewise, multiple units that can be lost in a single contingency provide less reliability than ones whose outages are uncorrelated.
- Low Flexibility – Some units require lengthy startup notification times, such as older steam turbines. They are less likely to be able to support reliability during critical periods that arise unexpectedly.

Hence, we recommend that the ISO develop capacity accreditation rules based on each resource's marginal reliability value (See Recommendation #2020-2a).

ISO-NE uses a resource adequacy model to determine its Installed Capacity Requirement (ICR). Hence, it is important to model each resource type accurately so that the ICR is high enough to maintain reliability and the accreditation of each resource type is consistent with its marginal reliability contribution. This will require the ISO to enhance the resource adequacy model to properly consider the limitations and availability of the five resource categories listed above. Hence, we recommend that the ISO modify how various resource types are modeled in MARS (See Recommendation #2020-2b).

Efficient Accreditation of Pipeline Gas Generators

ISO-NE awarded CSOs to 8 GW of generators that rely on fuel from natural gas pipelines and lack dual fuel capability in the most recent FCA. Hence, this is currently the largest class of resources whose marginal reliability value may significantly differ from the credit they are assigned in the FCM. In this report, we discuss a potential approach to determine the capacity value of these resources.

New England relies on imports of natural gas via the interstate pipeline system to supply fuel for winter heating, power generation, and other uses. On cold winter days, there is not enough interstate pipeline capacity to supply all of ISO-NE's gas generators after the heating demands of gas utilities are met. In recent winters, imports of liquefied natural gas (LNG) have allowed a portion of gas-only generators to operate. However, few generators have contracted for firm LNG deliveries, and it is unknown how much LNG will be available in future cold conditions.

We used a simplified resource adequacy model to simulate the marginal capacity value of pipeline gas-only resources that do not contract for firm LNG. Our model restricts the combined output of these resources on very cold days based on historical data showing that generation sourced from pipeline gas has been limited in peak winter conditions. We find that:

- The marginal value of gas-only capacity depends on whether reliability needs are concentrated in winter or summer. Gas-only resources have high marginal value for meeting reliability needs in summer when the pipeline system is not constrained. However, their value in the winter will depend on whether they can secure contracts to firm-up their gas supply.
- We estimate that if more than 5 to 6 GW of gas-only generation does not contract for firm fuel supply in the near future, the marginal value of these resources will be very low, which will increase winter reliability risks. Accordingly, marginal accreditation rules are needed to ensure that a sufficient portion of these resources are motivated to contract for firm fuel supply.

Our analysis underscores the importance of using a marginal approach to determine capacity credit. An alternative 'average' capacity value approach would provide approximately 70 percent capacity value even when the incremental value of these resources is zero, providing weak incentives to acquire firm fuel supplies or retire.

Assessment of the Mandatory Forward Capacity Market

ISO-NE conducts its Forward Capacity Auction (FCA) over three years before the associated capability period. Participation by loads in the three-year forward auction is mandatory, and it is the main avenue for suppliers to earn capacity revenues. We evaluate the efficacy of the mandatory three-year forward FCA and find that it has limited benefits and significant drawbacks compared to a "prompt" capacity market design in which auctions take place weeks or months before the capability period.

The main purported benefits of the FCA are that it provides revenue certainty to project developers and coordinates entry of exit of capacity in advance of when it is needed. However, any such benefits have diminished in recent years because ISO-NE no longer allows new resources to 'lock in' their initial FCA price for up to seven years. Hence, the FCA only provides price certainty for a single year, which does not significantly offset merchant risk for capital-intensive projects with amortization timeframes of twenty years or more.

The FCA has a dubious track record of coordinating timely entry of new resources even before the multi-year lock was eliminated. Just 42 percent of capacity from new large projects with initial CSOs from 2016 to 2022 entered on time, while 27 percent entered 1-2 years late and 31 percent never entered. The three-year forward period of the FCA is increasingly disconnected from the development time of new projects, such as solar, storage and demand aggregations, which are sometimes inhibited from earning timely capacity revenues by the forward market.

The three-year forward FCA has several disadvantages compared to a prompt capacity market:

- Participation in the FCA poses risk of financial penalties for a growing share of resources. These include large resources with uncertain development timeframes such as offshore wind and small resources such as distributed resource aggregations that lack certainty in the amount of capacity they can install three years in advance. A prompt market would simply begin compensating these resources as soon as they enter service without mandatory forward commitments.
- The FCA creates inefficient risk for old existing units that must commit to supplying capacity three to four years in the future. Unexpected issues can compel them to buy back their obligation at great cost and this risk can cause some resources to retire prematurely. A prompt market facilitates more efficient retirement decisions because the uncertainty regarding the condition and availability of older units is much lower.
- Key FCA parameters rely on resource mix assumptions that vary from the mix that actually clears the auction. This can cause the ICR and capacity credit values to become increasingly inaccurate, increasing the financial risk for projects whose capacity credit could change after the FCA. A prompt market allows more accurate assumptions regarding auction parameters because there is greater certainty about the resource mix.
- The FCA is conducted earlier than necessary for pipeline gas resources to firm up their capacity offers by contracting for LNG delivery. A prompt market would facilitate contracting for firm fuel at a time when such costs could be reflected in capacity offers.

Hence, we recommend eliminating the mandatory forward capacity auction and replacing it with a mandatory prompt capacity auction (see Recommendation #2021-1). The prompt auction should be conducted on a seasonal basis ahead of each summer and winter period using capacity market demand curves that reflect the marginal value of capacity in each season.

Financial Risk for New Capacity Investment

In early 2022, ISO-NE filed tariff changes to eliminate its Minimum Offer Price Rule (MOPR) beginning in the FCA19 auction to be held in 2025. An important consequence of eliminating the MOPR is that it will increase the financial risk for merchant resource owners. This may make it more difficult to attract new investment when it is needed for reliability.

Hence, we recommend that ISO-NE explicitly consider the impact of eliminating the Minimum Offer Price Rule (MOPR) on merchant generators' cost of capital when establishing the Net CONE value used in its capacity market demand curve (See Recommendation #2021-2).

Other Capacity Market Design Enhancements

The purpose of the capacity market is to provide a market mechanism to facilitate long-term investment and retirement decisions that ensure sufficient resources to satisfy the planning reliability requirements of New England. We evaluate potential market design improvements to facilitate competition in the auction and to enhance the incentives it provides.

Improving the Competitive Performance of the FCA

In our previous Annual Market Reports, we evaluated the supply and demand in the FCA and concluded that: a) Limited competition can enable a single supplier to unilaterally raise the capacity clearing price by a substantial amount; and that publishing information on qualified capacity and the Descending Clock Auction format help suppliers recognize when they can benefit by raising capacity prices.[3] Most of the pre-auction information available to auction participants regarding the existing, new and retiring resources either needs to be published for other purposes or is available from sources that are outside the ISO's purview. However, the ISO's DCA process provides key information on other suppliers offers that is not relevant for constructing competitive offers, and instead would allow a resource to raise its offer above competitive levels. A sealed bid auction would eliminate such information and improve the incentives for suppliers to submit competitive offers.

In addition, the descending clock auction format adds unnecessary complications to the capacity auction process that may preclude other potential market enhancements such as: (a) a more efficient representation of transmission interfaces that separate individual capacity zones, and/or (b) more accurate determinations of the marginal reliability value of specific resource types. A sealed bid format would likely facilitate these and other potential market enhancements. Hence, we recommend the ISO transition to a sealed-bid auction. (See Recommendation #2015-7)

Table of Recommendations

Although we find that the ISO-NE markets have generally performed competitively and efficiently, we identify a number of opportunities for improvement. Therefore, we make the following recommendations based on our evaluation of the ISO-NE markets, indicating those we believe will deliver the highest benefits and those than can be implemented relatively quickly.

The table below includes references to the location of our analyses and discussions supporting each recommendation. A number of the recommendations were first made in a prior annual report. Rather than repeating all past analyses and discussions, the reference is often to the most recent annual report containing the relevant discussion.

3 See our 2014, 2015 and 2017 *Assessment of the ISO New England Electricity Markets*.

Recommendation Number and Description		High Benefit[4]	Feasible in ST[5]	Report Reference
Reliability Commitments and NCPC Allocation				
2010-4	Modify allocation of "Economic" NCPC charges to make it consistent with a "cost causation" principle.		✓	2018 Report Section III
2020-1	Consider allowing firm energy imports from neighboring areas to satisfy local second contingency requirements.		✓	Section III.B
2014-5	Utilize the lowest-cost configuration for multi-unit generators when committed for local reliability.		✓	Section III.B
Reserve Markets				
2012-8	Introduce co-optimized operating reserves in the day-ahead market reflecting forecasted system needs.	✓		Section III.A
2019-3	Dynamically define a full set of local operating reserve requirements in the day-ahead and real-time markets.	✓		Section III.B
2014-7	Eliminate the forward reserve market.		✓	2014 Report Section I.B.
External Transactions				
2016-5	Pursue improvements to the price forecasting or other reforms to improve Coordinated Transaction Scheduling.			2017 Report Section VI.C
Capacity Market				
2015-7	Replace the descending clock auction with a sealed-bid auction to improve competition in the FCA.			2017 Report Section IV.A
2018-7	Modify the PPR to rise with the reserve shortage level, and not implement the remaining planned increase in the payment rate.	✓	✓	2019 Report Section V
2020-2	Improve capacity accreditation by: a) Accrediting all resources consistent with their marginal reliability value, and b) modify the planning model to accurately estimate marginal reliability values.	✓		Section IV.A-B
2020-3	Account for energy efficiency as a reduction in load instead of as a supply resource in the FCM.		✓	2020 Report Section V
2021-1	Replace the forward capacity market with a prompt seasonal capacity market.	✓		Section IV.C
2021-2	Include the effects of MOPR elimination on investment risk when establishing the net CONE for the demand curve.		✓	Section IV.D

4 Recommendation will likely produce considerable efficiency benefits.

5 Complexity and required software modifications are likely limited.

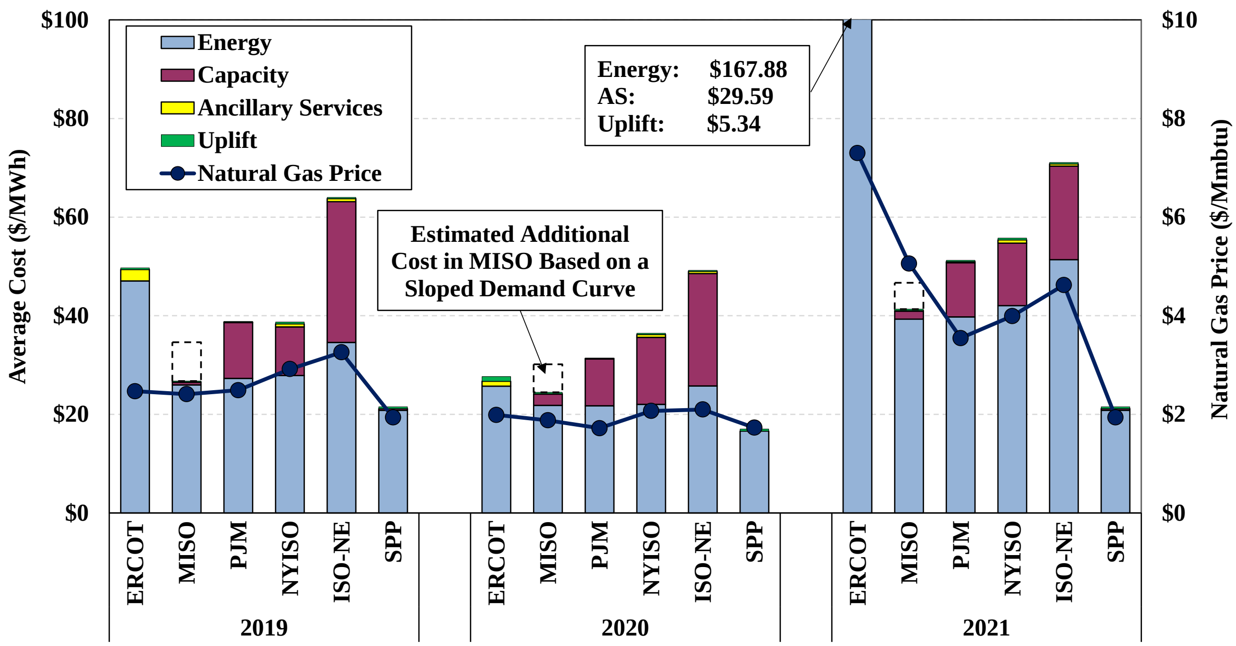
I. Comparing Key ISO-NE Market Metrics to Other RTOs

The 2021 Annual Markets Report by the Internal Market Monitor (IMM) provides a wide array of descriptive statistics and useful summaries of the market outcomes in the ISO-NE markets. The IMM report provides a very good discussion of these market outcomes and the factors that led to changes in the outcomes in 2021. Rather than duplicating this discussion, we attempt to place the key market outcomes into perspective in this section by comparing them to outcomes and metrics in other RTO markets.

A. Market Prices and Costs

While the RTOs in the US have converged to similar market designs, including Locational Marginal Pricing (LMP) energy markets, operating reserves and regulation markets, and capacity markets (with the exception of ERCOT), the details of the market rules can vary substantially. In addition, the market prices and costs in different RTOs can be significantly affected by the types and vintages of the generation, the input fuel markets and availability, and differences in the capability of the transmission network. To compare the overall prices and costs between RTOs, we produce the "all-in price" of electricity in Figure 1.

Figure 1: All-In Prices in RTO Markets[6]
2019 – 2021



The all-in price metric is a measure of the total cost of serving load. The all-in price is equal to the load-weighted average real-time energy price plus capacity, ancillary services, and bid

6 These include only wholesale market costs and not, for example, costs recovered through regulated retail rates. Such costs may be large in vertically-integrated areas such as MISO.

production guarantee uplift (referred to as "make-whole uplift" industry wide) costs per MWh of real-time load across each system. We also show the average natural gas price because it is the principal driver of generators' marginal costs and energy prices in most markets.

Energy Costs. This figure shows some clear sustained differences in prices and costs between these markets. ISO-NE has exhibited the highest energy prices of these markets with the exception of ERCOT. The relatively high energy costs in New England are primarily attributable to higher natural gas prices at pipeline delivery locations in New England. The high energy costs in ERCOT result from a combination of: (a) more frequent operating reserve shortages because its "energy-only" market that has produced relatively low planning reserve margins, (b) high operating reserve demand curves that result in high shortage pricing, and (c) extraordinary shortages that occurred during Winter Storm Uri in February 2021. Other key factors that affect relative energy costs in New England include:

- *Carbon Emission Costs.* ISO-NE energy prices are affected more than other regions by the costs of complying with state programs to limit greenhouse gas emissions. In 2021, compliance added an average of approximately $8 to 10 per MWh to the production costs of gas-fired combined cycle generators in Massachusetts and $4 to $5 per MWh in the other five New England states that are in the Regional Greenhouse Gas Initiative (RGGI) region. NYISO generators are also subject to RGGI compliance costs. In contrast, there are no such programs for generators in ERCOT, MISO, or SPP. RGGI compliance costs are included in a small number of PJM states in 2021.
- *Transmission Congestion Costs*. Although we do not show the most congested locations in neighboring markets (e.g., Long Island), some import-constrained locations exhibit energy prices substantially higher than prices in New England and contribute to higher system-wide average prices in those markets. Conversely, the unusually low levels of transmission congestion in New England tends to reduce system-wide average energy prices. We discuss congestion levels in more detail in the next subsection.

Capacity Costs. The figure also shows that the capacity costs in New England were substantially higher than in the other RTOs. The capacity costs for NYISO were lower because of its larger capacity surplus, which has resulted partly because: (a) New York state has retained large amounts of nuclear capacity through out-of-market subsidies called Zero Emission Credits and (b) falling load forecasts have had more immediate effects in New York's "prompt market" design than in New England's "forward market" design over these three years. Load forecasts have played a key role in the differences in the outcomes between these two markets:

- Both markets have experienced significant declines in their load forecasts in recent years because of continued growth of energy efficiency programs and behind-the-meter solar installations, as well as changing consumption patterns.
- ISO-NE's load forecast for the summer of 2021 fell from 26.2 GW in the forecast performed in 2017 that was used to develop inputs for FCA 12 to 24.8 GW in the 2021

CELT Report, a reduction of 5 percent. The NYISO's load forecast for the summer of 2021 fell by only 2 percent over the same period.[7]

- The NYISO's downward revisions in its load forecasts are recognized immediately in the NYISO's prompt capacity market design. On the other hand, ISO-NE has made larger downward revisions and they are recognized on with four-year delay in New England's forward capacity market. This load forecast change has been a key contributor to the 44 percent decline in the FCM capacity compensation rate from the 2021/22 Capability Year to the 2025/26 Capability Year.

Lower capacity costs for PJM are attributable to its capacity surpluses, which have resulted from a larger amount of available of capacity imports and lower generation development costs. Low capacity costs in MISO are attributable to its poor market design and surpluses generally produced by its regulated utilities. MISO operates a capacity auction with a vertical demand curve that is not designed to reveal the true value of capacity. As a result, capacity prices are understated (as shown by the skeleton bar in the figure) and do not provide efficient long-term incentives. This is not a problem for the regulated entities in MISO because they receive revenues from retail ratepayers. However, a large quantity of generation owned by unregulated companies in MISO have retired uneconomically in recent years and MISO is now short of capacity in its Midwest region beginning in the 2022/2023 planning year. The figure shows that if MISO were to adopt an efficient sloped demand curve, the all-in prices would increase to a level that is closer to the levels in NYISO and PJM.

ERCOT and SPP both operate an "energy-only" market (i.e., no capacity market) with a shortage price of $9000 and $1100, respectively. Shortage pricing had a substantial impact on energy prices when ERCOT experienced reserve shortages. Several hours of shortage in the summer of 2019 raised annual average energy and reserve costs in ERCOT well above those costs in other markets in 2019, while several *days* of shortage in February 2021 during severe winter weather caused annual average energy and reserve costs in ERCOT to move off the chart. ERCOT relies primarily on shortage pricing to provide long-term incentives to facilitate investment and retirement decisions. This is only feasible in ERCOT because it does not enforce planning reserve requirements, unlike the other ISOs shown in this figure. Although SPP does not operate a capacity market, it enforces a 12 percent planning reserve requirement.

Uplift Costs. The final result shown in the figure, although difficult to discern, is the average uplift costs per MWh of load in each region. Although this amount is small, it is important because it is difficult to hedge and tends to occur when the market requirements are not fully aligned with the system's reliability needs or prices are otherwise not fully efficient. The largest outlier in this area is ERCOT who adopted extremely conservative operating procedures

[7] See NYCA Summer Peak Demand Baseline forecast in the 2017 and 2021 *Load & Capacity Data "Gold Book"* reports.

beginning in July 2021, which has resulted in substantial out-of-market actions and uplift costs exceeding $5 per MWh of load. We discuss uplift in more detail in Subsection C.

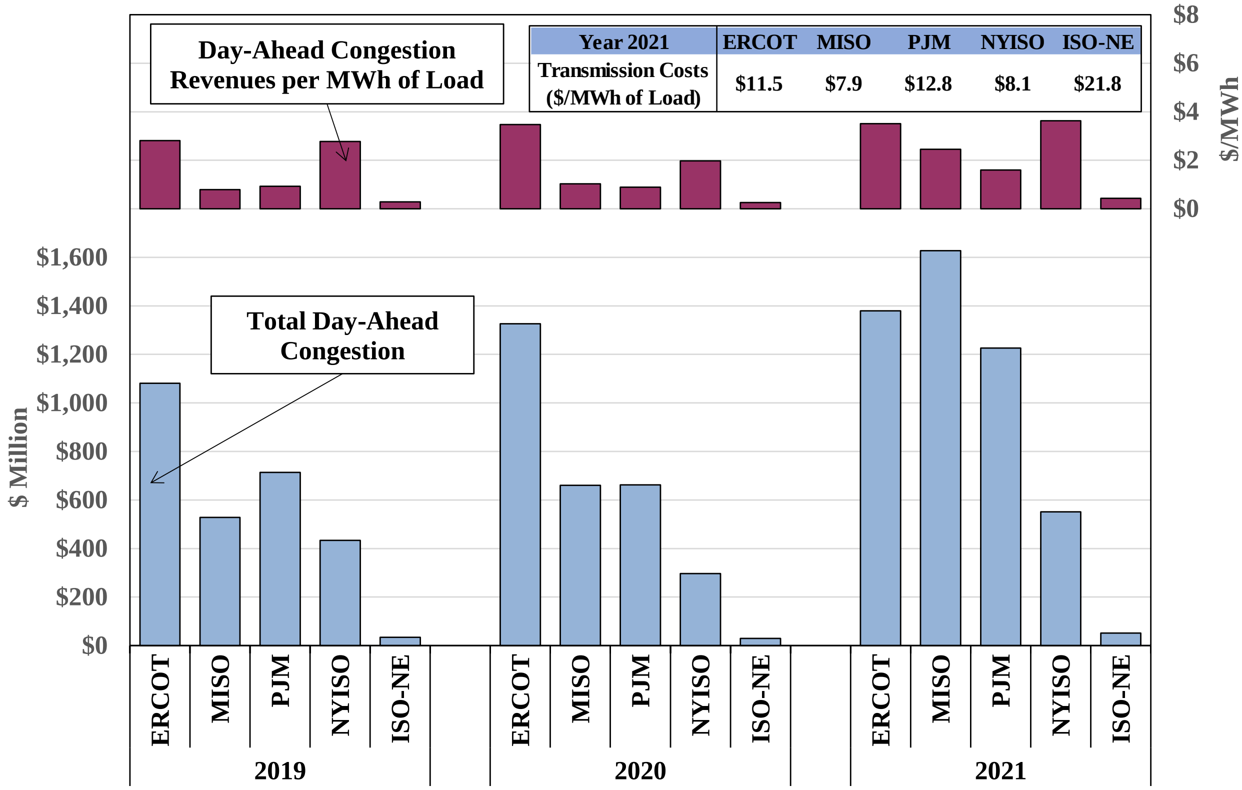
B. Transmission Congestion

One of the principal objectives of the day-ahead and real-time markets is to commit and dispatch resources to control flows on the transmission system and efficiently manage transmission congestion. Figure 2 shows the amount of congestion revenue collected through the day-ahead markets in a number of RTO markets in the U.S. To account for the very different sizes of these RTOs, we show the total amount of day-ahead congestion revenues divided by actual load in the top panel of the figure.

Figure 2 shows that ISO-NE experiences far less congestion than any of these other RTOs, averaging less than $0.38 per MWh. On this basis, congestion levels in the other RTOs are five to ten times larger than in New England. The low level of congestion in New England is not a surprise given the substantial transmission investments that were made over the past decade. These investments have led transmission rates to be nearly $22 per MWh in 2021, which are more than double the average rates in the other RTO areas shown in the figure.

Figure 2: Day-Ahead Congestion Revenues

2019-2021



The transmission rates in other RTO areas are much lower than in New England, even given the billions in incremental transmission costs that have been incurred in Texas and MISO to support the integration of wind resources. For example, ERCOT has incurred more than $5 billion in transmission expansion costs to mitigate the transmission congestion between the wind resources in west Texas and the load centers in eastern Texas, while MISO began investing in transmission projects anticipated to exceed $15 billion to integrate renewable resources throughout MISO.

Likewise, the NYISO and New York State have approved over $13 billion in transmission projects. Construction started on some components in 2019, but the vast majority of construction costs will be incurred over the next five years, while the impact to ratepayers will be spread over the next 25 to 30 years. These transmission upgrades principally focus on delivering renewable energy from upstate New York to load centers in New York City and Long Island, although the NYISO is currently conducting a major solicitation for transmission to move offshore wind output from Long Island to other areas of the state.

Hence, the primary reasons for transmission expansion in ERCOT, MISO, and NYISO have been to increase the deliverability of renewable resources to consumers. In contrast, the transmission investments in ISO-NE have generally been made for different reasons:

- In northern New England, transmission upgrades have been focused on improving the performance of the long 345 kV corridors, particularly through Maine.
- In southern New England, investments have been made to satisfy ISO New England's planning requirements to ensure the ISO can maintain reliability in the face of generation retirements throughout this area.

ISO New England's reliability planning process identifies a local need for transmission whenever the largest two contingencies would result in the loss of load under a 90th-percentile peak load scenario. This criterion is much more stringent than the reliability planning criteria used in the other three markets. A total of 834 project components have been placed in service across the region since 2002 and another 47 project components are either under construction or planned or proposed over the planning horizon. The estimated investment in New England to maintain reliability was $11.7 billion from 2002 to March 2022, and another $1.1 billion is planned by 2030.

In general, transmission investment is economic when the marginal benefit of reducing congestion is greater than the marginal cost of the transmission investment. Given that the average congestion cost per MWh of load in New England has been roughly $0.32 per MWh over the past three years, it is unlikely that additional transmission investment would be economic in the near term. Nonetheless, past transmission investment has eliminated substantial local reliability NCPC costs and better prepared the system to integrate renewable resources in the future.

C. Uplift Charges and Cost Allocation

Although NCPC costs (generally referred to as "Make-Whole Uplift Charges" industry-wide) generally account for a small share of the overall wholesale market costs, they are important because they usually occur when the market requirements are not fully aligned with the actual system reliability needs or when prices are otherwise not fully efficient. The cost of satisfying some needs will be reflected in NCPC payments rather than in market-clearing prices. Ultimately, this undermines the economic signals that govern behavior in the day-ahead and real-time markets in the short-term and investment and retirement decisions in the long-term. Thus, we evaluate the causes of NCPC payments to identify potential inefficiencies.

Table 1 summarizes the total day-ahead and real-time NCPC charges in ISO-NE over the past three years, and it shows the comparable 2021 uplift charges for both NYISO and MISO. Because the size of the ISOs varies substantially, the table also shows these costs per MWh of load. Recognizing that some RTOs differ in the extent to which they make reliability commitments in the day-ahead horizon versus real-time, the table includes a sum of all day-ahead and real-time uplift at the bottom to facilitate cross-market comparisons.

Table 1: Summary of Uplift by RTO

		ISO-NE			NYISO	MISO
		2019	2020	2021	2021	2021
Real-Time Uplift						
Total	**Local Reliability ($M)**	$2	$1	$2	$11	$2
	Market-Wide ($M)	$16	$15	$19	$12	$127
Per MWh of Load	**Local Reliability ($/MWh)**	$0.01	$0.01	$0.01	$0.07	$0.00
	Market-Wide ($/MWh)	$0.14	$0.13	$0.16	$0.08	$0.19
Day-Ahead Uplift						
Total	**Local Reliability ($M)**	$7	$4	$6	$28	$44
	Market-Wide ($M)	$6	$5	$9	$3	$26
Per MWh of Load	**Local Reliability ($/MWh)**	$0.06	$0.04	$0.05	$0.18	$0.07
	Market-Wide ($/MWh)	$0.05	$0.05	$0.08	$0.02	$0.04
Total Uplift						
Total	**Local Reliability ($M)**	$9	$5	$8	$39	$46
	Market-Wide ($M)	$22	$21	$28	$15	$153
Per MWh of Load	**Local Reliability ($/MWh)**	**$0.07**	**$0.05**	**$0.07**	**$0.25**	**$0.07**
	Market-Wide ($/MWh)	**$0.19**	**$0.18**	**$0.24**	**$0.10**	**$0.23**
	All Uplift ($/MWh)	**$0.26**	**$0.22**	**$0.31**	**$0.35**	**$0.30**

Market-Wide Uplift. Table 1 shows that ISO-NE incurred more market-wide uplift costs than the other two markets, adjusted for its size. In 2021, uplift charges increased in all three regions as a result of higher natural gas prices and load levels following the pandemic, although ISO-NE's market-wide NCPC uplift was more than double the cost per MWh of load incurred by NYISO and slightly higher than that in MISO. MISO saw a substantial increase in uplifts because of substantial increase in out-of-market commitments that were have been investigating.

The higher uplift costs in New England are attributable to at least two factors:

- Lower market-wide costs for NYISO and MISO are partly attributable to their day-ahead ancillary services markets, which allow a larger share of the costs of committing resources needed for operating reserves to be reflected in the market. We discuss these factors in more detail in Section III.
- Second, while all three markets have rules for compensating a generator whose scheduled output level differs from its most profitable output level, ISO-NE's rules provide compensation in some circumstances when the MISO and NYISO rules do not. It would be beneficial to examine these differences to identify best practices across markets.

Local Reliability Uplift. Table 1 also shows that local reliability NCPC uplift has been relatively low in the past three years. This reflects low levels of supplemental commitments in the load pockets because of transmission upgrades and new market entries in these areas. Uplift for local reliability in ISO-NE was generally in line with the MISO market, but was much smaller than in the NYISO. In the NYISO, a large amount of generation is committed in the day-ahead market for local second contingency protection in several the load pockets across the state, primarily in New York City. In addition, oil-fired peaking resources are often dispatched out-of-merit on Long Island in real-time to manage local voltage needs or congestion on the 69 kV network. These local transmission security and reliability requirements are not adequately reflected in the NYISO energy and reserve markets, leading to inefficient market prices, higher uplift costs, and poor incentives for investment in resources that could help maintain local security and reliability.

Uplift Allocation. In addition to the differences in the magnitude of the uplift costs, the allocation of the uplift costs also varies substantially among the RTOs. ISO-NE allocated approximately half of the real-time NCPC charges to real-time deviations, including virtual transactions. However, most of the NCPC charges that are allocated to real-time deviations are not caused by them. This misallocation of NCPC charges distorts market incentives to engage in scheduling that can lead to real-time deviations. Unfortunately, this distortion is compounded by the fact that NCPC charges are allocated to real-time deviations that actually help reduce NCPC charges, such as virtual load and over-scheduling load in the day-ahead market.

Over-allocating NCPC charges to real-time deviations has resulted in higher costs for virtual transactions in New England than in other RTO markets, which tends to reduce their participation in the market and the overall market liquidity. This is undesirable because in organized wholesale power markets, virtual trading plays a key role in the day-ahead market by providing liquidity and improving price convergence between day-ahead and real-time markets.

Table 2 shows the average volume of virtual supply and demand that cleared the three eastern RTOs we monitor as a percent of total load, as well as the gross profitability of virtual purchases and sales. Gross profitability is the difference between the day-ahead and real-time energy prices used to settle the energy that was bought or sold by the virtual trader. The profitability does not account for uplift costs allocated to virtual transactions, which are shown separately.

Table 2: Scheduled Virtual Transaction Volumes and Profitability

Market	Year	Virtual Load		Virtual Supply		Uplift Charge Rate
		MW as a % of Load	Avg Profit	MW as a % of Load	Avg Profit	
ISO-NE	2018	2.7%	$1.10	4.5%	$2.69	$0.94
	2019	2.3%	-$1.20	4.9%	$1.26	$0.40
	2020	2.8%	$0.36	4.6%	$0.72	$0.46
	2021	2.8%	-$1.29	4.5%	$2.07	$0.53
NYISO	2021	6.2%	$0.95	9.7%	$0.73	< $0.1
MISO	2021	11.3%	$0.75	11.7%	$1.64	$0.37

Table 2 shows that virtual trading was generally profitable, indicating that it has generally helped improve price convergence between the day-ahead and real-time markets. The gross volume of cleared virtual transactions (including both virtual load and virtual supply) averaged around 7 percent of load in the ISO-NE market each year from 2018 to 2021. This is much lower than the 16 percent in the NYISO market and the 23 percent in the MISO market observed in 2021.

We believe this substantial difference is largely due to the relatively high amount of uplift costs allocated to virtual transactions under ISO-NE's NCPC allocation methodology, which raises significant concerns. In spite of the decrease in recent years, the NCPC charges remain higher and more uncertain than the charges imposed by the other RTOs. Additionally, it results in large NCPC cost allocations to virtual load even though virtual load generally *reduces* NCPC costs. This provides a substantial disincentive for firms to engage in virtual trading, ultimately reducing liquidity in the day-ahead market. This explains why the gross profitability of virtual transactions is usually larger in ISO-NE than the other RTOs (i.e., the day-ahead and real-time prices are not as well arbitraged).

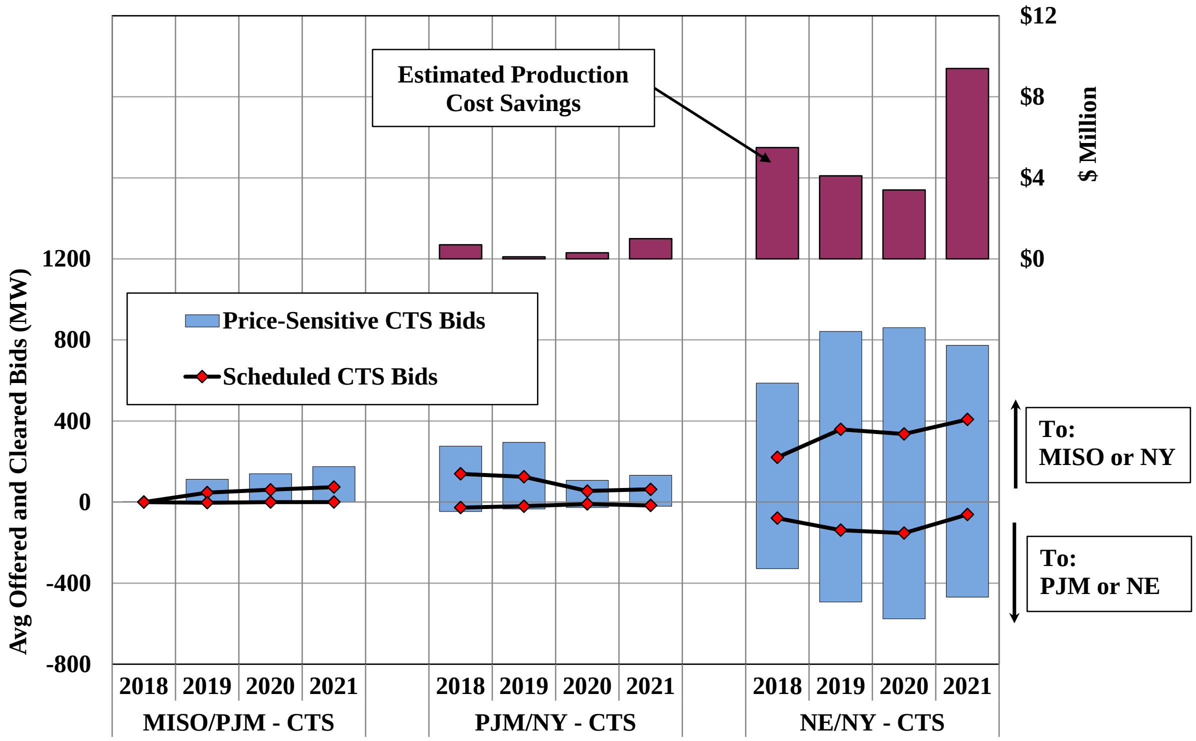
Hence, we continue to recommend the ISO modify the allocation of Economic NCPC charges to be consistent with "cost causation" principles, which would involve not allocating NCPC costs to virtual load and other real-time deviations that do not cause real-time economic NCPC (See Recommendation #2010-4). This will be necessary when the ISO implements day-ahead ancillary services markets and addressing both recommendations together would be reasonable.

D. Coordinated Transaction Scheduling

Coordinated Transaction Scheduling (CTS) is a market process whereby two neighboring RTOs exchange real-time market information to schedule external transactions more efficiently. CTS is very important because it allows the large interface between markets to be more fully utilized, which lowers costs and improves reliability in both areas. The benefits of CTS are likely to grow in the future as the addition of intermittent generation makes it more difficult for RTOs to balance supply and demand.

Figure 3 compares the performance of the CTS scheduling process between ISO-NE and NYISO with the CTS processes between PJM and NYISO and between MISO and PJM. The bottom portion of the figure shows annual average quantities of price-sensitivity of CTS bids and schedules from 2018 to 2021.[8] Positive numbers indicate transactions offered and scheduled from neighboring markets to the NYISO or MISO markets, while negative numbers represent transactions offered and scheduled from neighboring markets to the PJM or New England markets. The upper portion of the figure shows the market efficiency gains (and losses) from CTS, which is measured by production cost savings. However, we did not estimate the cost savings for the process between PJM and MISO because of very limited participation.

Figure 3: CTS Scheduling and Efficiency
2018 – 2021



The results in Figure 3 show that the participation of CTS has been much more robust at the NE/NY interface than at the PJM/NY and PJM/MISO interfaces. The average amount of price-sensitive bids that were offered and cleared was significantly larger at the NE/NY interface because large transaction fees are imposed at both the PJM/NY and PJM/MISO interfaces while there are no substantial transmission charges or uplift charges on transactions at the NE/NY interface. For example, CTS transactions from NYISO to PJM incur charges typically ranging from $6 to $8 per MWh, while CTS transactions from MISO to PJM incur reservation charges of $0.75 per MWh based on the offered quantity and an additional $1.75 per MWh based on the cleared quantity. Accordingly, very few price-sensitive CTS transactions were offered and scheduled from NYISO or MISO to PJM.

8 CTS bids in the price range of -$10 to $10 per MWh are considered price-sensitive for this evaluation.

On the other hand, CTS transactions from PJM to MISO or NYISO typically incur a smaller charge (between $1 and $2 per MWh) than CTS transactions in the opposite direction, leading to significantly more activity in that direction. These results demonstrate that these charges are a significant economic barrier to achieving the potential benefits from the CTS process because they deter participants from submitting efficient CTS offers.

The estimated production cost savings from the CTS process between New England and New York totaled over $22 million in the four-year period from 2018 to 2021, while the estimated savings were just $2 million at the PJM/NY interface.[9] In addition to higher price-sensitive bids, better price forecasting was another key contributor to higher savings at the NE/NY interface.

ISO-NE's price forecasting is generally more accurate than PJM's price forecasting. This is partly because ISO-NE forecasts a supply curve (with 7 points representing different interchange levels at the interface), while PJM only forecasts a single price point at one assumed interchange level. Nonetheless, our evaluation of the price forecasting errors at the NE/NY interface have indicated that further improvements in price forecasting are possible.10 If the ISOs can address these areas and further improve the price forecasts that underlie the CTS prices, it should ultimately allow the process to achieve larger savings. Therefore, there is ample opportunity to improve the performance of the CTS process at the NE/NY interface.

Available improvements to the forecasts may be limited by the fact that they must be produced roughly 40 minutes in advance. An alternative process that we have evaluated for MISO and PJM is to make interchange adjustments each interval based on the most recent real-time prices. The estimated savings of such a process for MISO and PJM were much larger than the savings that have been achieved by any of the current CTS processes and may justify consideration for New England and New York.

E. Net Revenues for New Entrants

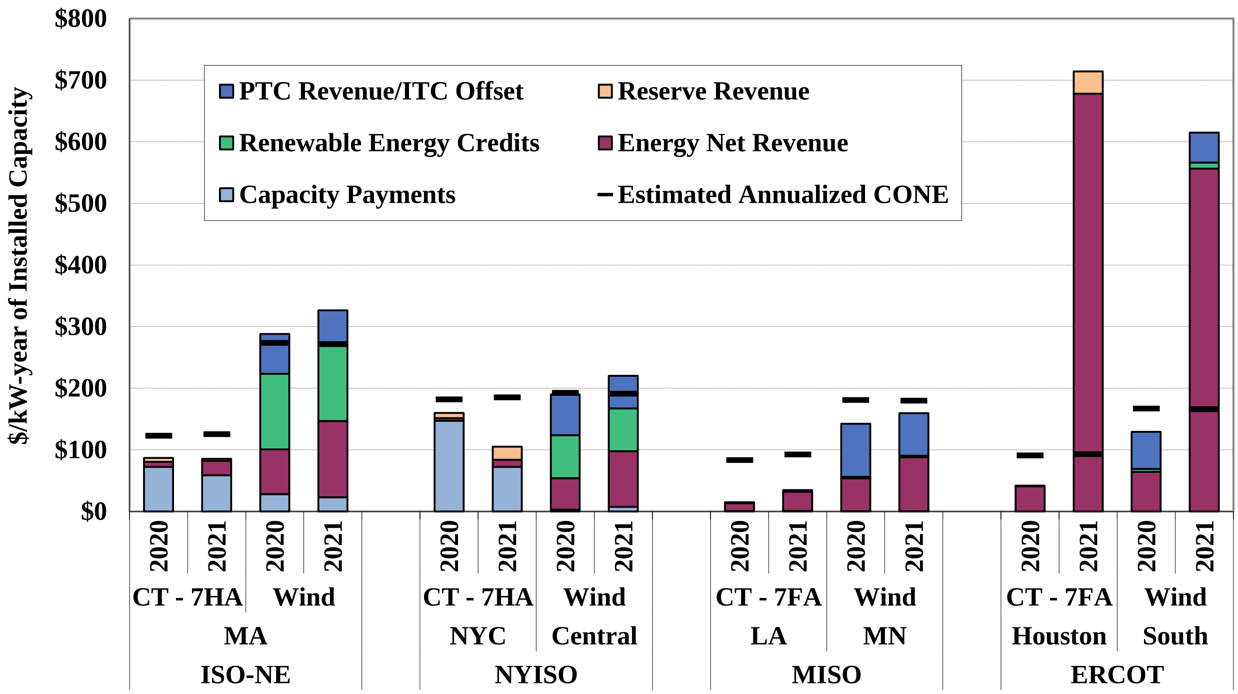
A well-functioning wholesale market establishes transparent and efficient price signals that guide investment and retirement decisions. Wholesale prices motivate firms to invest in new resources, maintain existing generation, and/or retire older units. The New England states have set ambitious policy goals for decarbonizing the electricity sector and implemented a number of programs to encourage development of clean energy resources. Robust and efficient market incentives will help the states satisfy their goals at the lowest possible cost. This is true even for projects that are primarily motivated by state and federal incentives because wholesale prices still play a significant role in the overall profitability of most projects.

9 Production cost savings are calculated relative to our estimates of scheduling that would have occurred under the previous hourly scheduling process. To estimate the adjustment in the interchange schedule attributable to the intra-hour CTS scheduling process, we compare the final CTS schedule to advisory schedules in NYISO's RTC model that are determined 30 minutes before each hour.

10 See Section VI.C in our *2017 Assessment of the ISO New England Electricity Markets*.

This section compares the incentives for new investment in ISO-NE to three other markets by estimating the net revenue new generating units would have earned from the wholesale market and the applicable state and federal incentives. Figure 4 shows the estimated net revenues for a new combustion turbine and a land-based wind facility divided into the following categories: (a) energy net revenues based on spot prices, (b) capacity payments based on auction clearing prices and pay-for-performance incentives, (c) operating reserve net revenues, (d) federal production tax credits, and (e) state renewable energy credits. [11] For comparison, the figure also shows the estimated annual net revenue that would be needed for these new investments to be profitable (i.e., the "Cost of New Entry" or CONE) in 2020 and 2021.

Figure 4: Net Revenues Produced in ISO-NE and Other RTO Markets
2020 – 2021



Incentives for New Combustion Turbines (CT)

New CT investments in ISO-NE and NYISO are heavily reliant on capacity revenues. In ISO-NE, the capacity and energy prices over the last two years would generally not incent new entry of CTs. This is efficient for a market with surplus capacity, where new entry is likely to occur only if a resource has specific advantages (e.g., cost savings due to repowering, access to cheaper gas, usage of a more advanced technology, etc.). The capacity surplus and associated decline in capacity prices will continue through at least 2025/26 CCP.

11 See Appendix Section VI for the assumptions used for this analysis. The combustion turbines chosen for each market reflect those that are most economic and likely to be built: a F Class Frame CT (7FA) in MISO and ERCOT and a H Class Frame CT (7HA) in New England and New York because of siting regulations.

Net revenues for a CT from the energy and reserve markets increased in 2021 in all markets because of natural gas prices and electricity demand returning to more normal levels after the pandemic year of 2020.

- *New York City*. The only location where total net revenues decreased in 2021 was New York City, where capacity prices fell primarily because of a shift of the locational capacity requirements from New York City to other areas starting in the summer of 2021.
- *ERCOT*. The net revenues of a CT in ERCOT rose substantially from 2020. Shortage pricing at $9,000 per MWh for several *days* in February led net energy and reserve revenues to rise to more than seven times the estimated net CONE in 2021. However, capturing these net revenues would have required resources to be online or selling reserves and unfortunately many ERCOT's gas-fired resources could not run during this event because of the effects of the cold temperatures or fuel availability.
- *MISO South*. Of the locations analyzed, a CT in Louisiana exhibited the lowest estimated net revenue because of the region's sizeable capacity surplus and because the vertical capacity demand curves used in MISO lead to inefficiently low capacity prices. Adopting a sloped demand curve would have substantially increased capacity net revenue and reduced the shortfall in the annual revenue requirement of the CT.

Although shortage pricing is a very important component of the expected revenues in both ISO-NE and ERCOT, a large share of ISO-NE's shortage pricing is settled through its PFP framework. This PFP approach alters the financial risks to consumers and suppliers under extreme conditions in at least five ways:

i. The performance payments are a transfer from underperforming to overperforming resources. Hence, there is no direct increase in consumer payments.[12]

ii. ISO-NE has stop-loss provisions that limit, on a monthly and annual basis, the losses that a capacity resource could incur due to poor performance in PFP events.[13] These provisions limit the financial risk to generators while generally maintaining significant supplier incentives to perform during shortages. Aside from PFP, the operating reserve demand curves can set energy and reserve clearing prices above $2,500 per MWh.

iii. The stop-loss provisions can also limit the compensation for generators that perform well during sustained shortages, which may weaken the incentives that PFP provides.

iv. The expected frequency of shortages in New England is lower by design because the capacity market is designed to produce a higher reserve margin than in an energy-only market like ERCOT.

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12 Although the PFP framework does not result in direct increase in consumer costs from higher prices during shortage events, it should increase capacity prices as capacity suppliers raise their offers in the FCM.

13 "Under the monthly stop-loss limit, in any one month, the maximum amount that can be subtracted from a resource's Capacity Base Payment for that month is the resource's Capacity Supply Obligation quantity times the FCA starting price. Under the annual stop-loss limit, the maximum amount that a capacity resource can lose is equal to three times the resource's maximum monthly potential net loss." See pp 42 of FERC Order on May 30, 2014 in Docket Nos. ER14-1050-000, ER14-1050-001 and EL14-52-000.

v. ISO-NE's pricing under PFP of very small shortages of 30-minute reserves, which are difficult to forecast, is much more aggressive than pricing in ERCOT or any other market. This increases the risk for participants and is inefficient to the extent that these modest shortages raise only small reliability concerns.

Hence, although there are similarities in pricing and supplier incentives during shortage events, the profile of the risks faced by suppliers and consumers, as well as the likelihood of shortage events, is considerably different in ISO-NE than a typical energy-only market like ERCOT.

Incentives for New Wind Projects

The net revenues for a land-based wind unit in New England exceeded its CONE in 2021 because of higher energy revenues. State and federal incentives were still the primary source for revenues, accounting for 55 percent of total net revenues in 2021. Market revenues are also important because they provide critical price signals that differentiate the value of resources based on the needs of the power system. Wholesale markets complement state policies by guiding investment towards more efficient technologies and locations, enabling the more economic resources to win policy-driven solicitations.

The market for Class I RECs in New England continued to be tight in 2021. High prices in 2021 were likely driven by (i) increases in state RPS requirements (which increases the demand), and (ii) delays in the anticipated completion of offshore wind projects (which reduces the supply).[14] Although prices in the past two years have been high, REC prices have historically been volatile.

Figure 4 shows that the incentive to invest in wind resources varies widely in other markets. Resources in New York receive significant REC revenues and further benefit from long-term contracts for 20 years with NYSERDA, which contributes to them being economic in New York.[15] However, renewable resources in most of MISO and ERCOT do not receive significant REC revenues. This contributed to the resources not receiving sufficient net revenue to be economic in recent years (with the exception of 2021 in ERCOT), despite that fact that the resource potential in MISO and ERCOT is normally better than in New England and New York.

Ultimately, however, the investment incentives in wind resources will depend not only on wholesale prices, but also on the offtake contract structures employed in different regions:

- Long-term PPAs are the dominant mechanism for stabilizing revenues for renewable resources in ISO-NE and NYISO.
- ERCOT has been transitioning from long-term PPAs to private financial hedges.[16]

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14 See April 13, 2021 market update from Power Advisory LLC.

15 The figure shows the average Tier 1 REC sale price posted by NYSERDA, whereas NE price is based on MA Class I REC broker quotes as reported by S&P Financial.

16 In recent years, Virtual PPAs of wind projects with a corporate off taker has also grown, with total amounts in 2021 comparable to the amount of capacity with traditional PPAs. See articles from S&P Global.

Incentive Effects of PPAs. PPAs (typically with utilities) generally involve a fixed-price for every MWh generated by the project and tend to be 20-years long. The buyers in such contracts (ultimately consumers) generally assume two key risks:

- Basis risk (i.e., risk of congestion between the wind node and the hub); and
- Volumetric risk (i.e., risk of underperformance which would require buyers to purchase any shortfall at spot prices).

This is not ideal because consumers typically have very little control over where the project is sited, the technology used in the project, and project operation and maintenance. Hence, project owners are in a better position to manage these risks when compared to off takers.

Incentive Effects of Financial Hedges. Hedges between private entities have allowed for significant development of clean energy resources in other markets (e.g., ERCOT). This demonstrates that renewable resources can be developed on a merchant basis, even if there are no opportunities for PPAs with state agencies or regulated utilities. Under a typical hedge, the wind project owner sells a certain amount of energy subject to a strike price that is based on the price at a pre-determined location.[17]

Overall, owners of projects that are financed using hedges are exposed to the basis risk and volumetric risk that projects with traditional PPAs do not face. This is good because the wind unit owner/operator is in the best position to manage these risks. For example, several wind unit owners in ERCOT that could not perform during the arctic event in February 2021 have reported significant financial losses, unit foreclosures, and/or a change in their hedging strategy.[18] If units under PPAs underperform, it is the ratepayers, rather than the wind unit owner, that would generally bear the costs of the poor performance.[19]

Even though financing new wind resources with financial hedges is effective and efficient, the availability of attractive PPAs offered by state agencies or regulated utilities will inhibit hedging with private counterparties. Additionally, long-term PPAs can create large shocks in renewable supply that lead to volatility of tradable REC prices, capacity prices, and energy prices, which would further inhibit hedging with private counterparties.

17 If the locational price is lower than the strike price, the hedge provider pays the difference to the owner. If the hub price is higher than the strike price, the owner pays the difference to the hedge provider. The duration of the hedges is 10-13 years and these agreements usually do not cover the full output of the unit.

18 For instance, see articles in trade press about impact of hedges on Innergex and RWE, and multiple wind generators requesting the Texas PUC to reprice power to avoid “severe financial losses”.

19 Since the PFP payments/ penalties are transfers between generators, to the extent that the production from the underperforming asset was required to meet load, ratepayers will see spot prices that include the RCPF adders, but not the Performance Payment Rate (PPR). The PPR for FCA-16 is set at nearly $8900 per MWh, while the RCPF for TMOR is $1000 per MWh.

II. COMPETITIVE ASSESSMENT OF THE ENERGY MARKET

This section evaluates the competitive performance of the ISO-NE energy market in 2021. Although LMP markets increase overall system efficiency, they may provide incentives for exercising market power in areas with limited generation resources or transmission capability. Most market power in wholesale electricity markets is dynamic, existing only in certain areas and under particular conditions. The ISO employs market power mitigation measures to prevent suppliers from exercising market power under these conditions. Although these measures have generally been effective, it is still important to evaluate the competitive structure and conduct in the ISO-NE markets because participants with market power may still have the incentive to exercise market power at levels that would not warrant mitigation.

Based on the analysis presented in this section, we identify the geographic areas and market conditions that present the greatest potential for market power abuse. We use a methodology for measuring and analyzing potential withholding that was developed in prior assessments of the competitive performance in the ISO-NE markets.[20] We address four main areas in this section:

- Mechanisms by which sellers exercise market power in LMP markets;
- Structural market power indicators to assess competitive market conditions;
- Potential economic and physical withholding; and
- Market power mitigation.

A. Market Power and Withholding

Supplier market power can be defined as the ability to profitably raise prices above competitive levels. In electricity markets, this is generally done by either economically or physically withholding generating capacity. Economic withholding occurs when a resource is offered at prices above competitive levels to reduce its output or otherwise raise the market price. Physical withholding occurs when all or part of the output range of a resource is not offered into the market when it is available and economic to operate. Physical withholding can be accomplished by "derating" a generating unit (i.e., reducing the unit's high operating limit).

While many suppliers can increase prices by withholding, not every supplier can profit from doing so. Withholding will be profitable when the benefit of selling its remaining supply at prices above the competitive level is greater than the lost profits on the withheld output. In other words, withholding is only profitable when the price impact exceeds the opportunity cost of lost sales for the supplier. The larger a supplier is relative to the market, the more likely it will have the ability and incentive to withhold resources to raise prices.

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20 See, e.g., Section VIII, *2013 Assessment of Electricity Markets in New England*, Potomac Economics.

There are several additional factors (other than size) that affect whether a market participant has market power, including:

- The sensitivity of real-time prices to withholding, which can be very high during high-load conditions or high in a local area when the system is congested;
- Forward power sales that reduce a large supplier's incentive to raise prices in the spot market;[21] and
- The availability of information that would allow a large supplier to predict when the market may be vulnerable to withholding.

When we evaluate the competitiveness of the market or the conduct of the market participants, we consider each of these factors, some of which are included in the analyses in this report.

B. Structural Market Power Indicators

This subsection examines structural aspects of supply and demand that affect market power. Market power is of greatest concern in areas where capacity margins are small, particularly in import-constrained areas. Hence, this subsection analyzes the three main import-constrained regions and all New England using the following structural market power indicators:

- Supplier Market Share - The market shares of the largest suppliers determine the possible extent of market power in each region.
- Herfindahl-Hirschman Index (HHI) - This is a standard measure of market concentration calculated by summing the square of each participant's market share.
- Pivotal Supplier Test - A supplier is pivotal when some of its capacity is needed to meet demand and reserve requirements. A pivotal supplier has the ability to unilaterally raise the spot market prices by raising its offer prices or by physically withholding.

The first two structural indicators focus exclusively on the supply side. Although they are widely used in other industries, their usefulness is limited in electricity markets because they ignore that the inelastic demand for electricity substantially affects the competitiveness of the market.

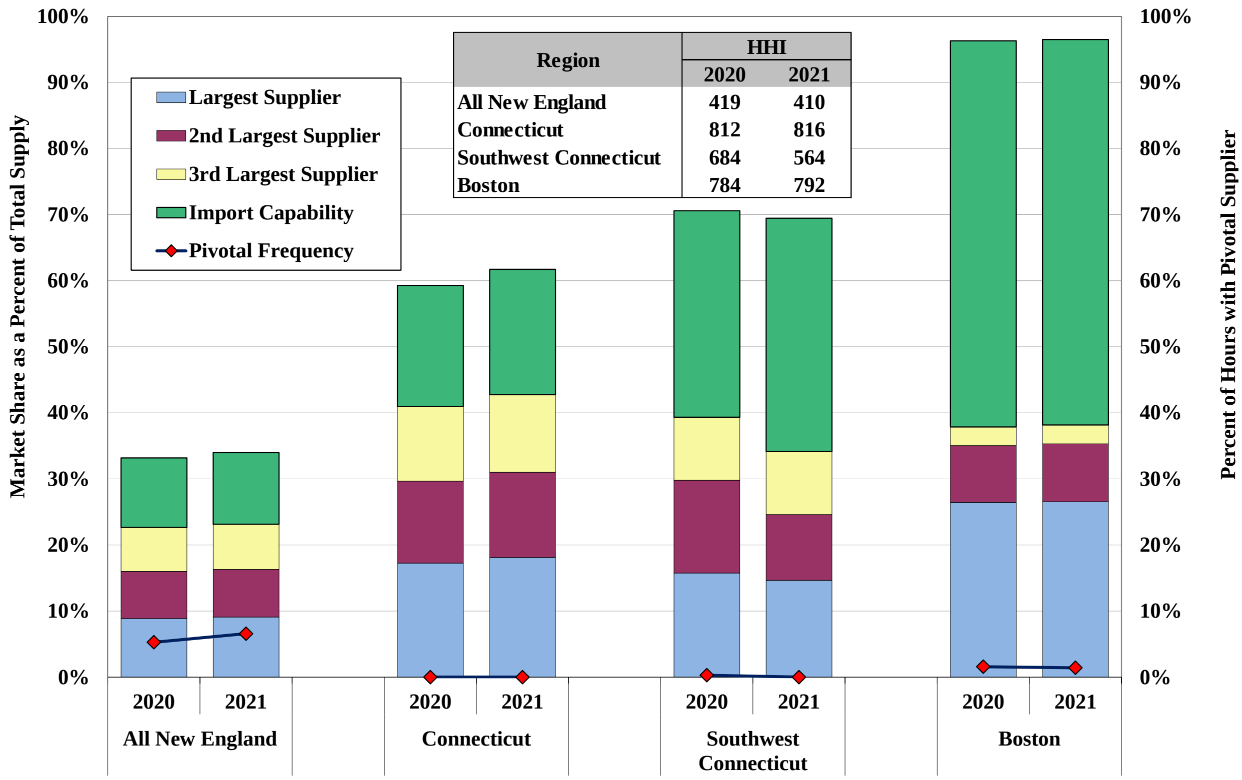
The Pivotal Supplier Test is a more reliable means to evaluate the competitiveness of energy markets because it recognizes the importance of both supply and demand. Whether a supplier is pivotal depends on the size of the supplier as well as the amount of excess supply (above the demand) held by other suppliers. When one or more suppliers are pivotal, the market may be vulnerable to substantial market power abuse. This does not mean that all pivotal suppliers should be deemed to have market power. Suppliers must have both the ***ability*** and ***incentive*** to raise prices in order to have market power. A supplier must also be able to foresee when it will

[21] When a supplier's forward power sales exceed the supplier's real-time production level, the supplier is a net buyer in the real-time spot market, and thus, benefits from low rather than high prices. However, some incentive still exists because spot prices will eventually affect prices in the forward market.

be pivotal to exercise market power. In general, the more often a supplier is pivotal, the easier for it to foresee circumstances when it can profitably raise market clearing prices. For the supplier to have the incentive to raise prices, it must have other unwithheld supply that would benefit from higher prices.

Figure 5 shows the three structural market power indicators for four regions in 2020 and 2021. First, the figure shows the market shares of the largest three suppliers and the import capability in each region in the stacked bars.[22,23] The remainder of supply to each region comes from smaller suppliers. The inset table shows the HHI for each region. We assume imports are highly competitive, so we treat the market share of imports as zero in our HHI calculation. The red diamonds indicate the portion of hours where one or more suppliers were pivotal in each region. We exclude potential withholding from nuclear units because they typically cannot ramp down substantially and would be costly to withhold due to their low marginal costs.

Figure 5: Structural Market Power Indicators
2020 – 2021



Region	HHI 2020	HHI 2021
All New England	419	410
Connecticut	812	816
Southwest Connecticut	684	564
Boston	784	792

22 The market shares of individual firms are based on information in the monthly reports of Seasonal Claimed Capability (SCC), available at: https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/seson-claim-cap. In this report, we use the generator summer capability in the July SCC reports from each year.

23 The import capability shown is the transmission limit from the latest Regional System Plan, available at: https://www.iso-ne.com/system-planning/system-plans-studies/rsp. The *Capacity Import Capability* is used for external interfaces, and the N-1-1 Import Limits are used for reserve zones.

Figure 5 indicates that market concentration of internal generation did not change significantly in most regions from 2020 to 2021. The portfolio sizes of the three largest suppliers remained similar from 2020 to 2021 in Boston, Connecticut, and all New England. However, the market share of the largest suppliers fell in Southwest Connecticut as PSEG retired its final coal-fired power plant, Bridgeport Harbor Station Unit 3, on June 1, 2021. In addition, the import capability into Southwest Connecticut increased modestly from 2020 to 2021 as a result of completed transmission upgrades n the 115 kV system.[24] Consequently, the HHI fell in that area.

There were variations in market concentrations among the largest internal suppliers in the four regions. In 2021, Boston had one supplier with a large market share of 27 percent (including import capability as a portion of the total supply into the area), while all New England had three suppliers with similar market shares of less than 10 percent each. Import capability accounted for a significant share of total supply in each region, ranging from 11 percent in all New England to 58 percent in Boston in 2021. Consequently, the market concentration (measured by the HHI) was relatively low, well under 1000 in all of the four areas. In general, HHI values above 1800 are considered highly concentrated by the U.S. Antitrust Agencies and the FERC for purposes of evaluating the competitive effects of mergers. However, this does not establish that there are no market power concerns. These concerns are most accurately assessed in our pivotal supplier analysis for 2021, which indicates that:

- In Southwest Connecticut and Connecticut, there were almost no hours when a supplier was pivotal.
- In Boston, although one supplier owned 64 percent of the internal capacity, it was pivotal in less than 2 percent of hours. This underscores the importance of import capability into constrained areas in providing competitive discipline; and
- In all New England, at least one supplier was pivotal in 7 percent of hours.[25]

The pivotal supplier frequency rose modestly from 2020 to 2021 largely because of higher load levels and lower net imports. Both average and peak load levels rose by roughly 1.6 percent from 2020 to 2021, reflecting continued demand recovery from the COVID-19 pandemic and more frequent weather-driven summer and winter peaking conditions. Net imports fell notably from 2020 to 2021 primarily across the interfaces with New York. The NYISO experienced substantially higher congestion across its Central-East interface in 2021 because of transmission outages and the retirement of the Indian Point nuclear facility, making it more costly to import

24 Southwest Connecticut 2022 Upgrades were all placed in service by February 2021, which included rebuilding and reconductoring lines, installing new lines, rebuilding two substations, and adding reactive support to maintain voltage, all on the 115kV network.

25 The pivotal supplier results are conservative for "All New England" compared to those evaluated by the IMM primarily because of our differences in: (a) treatment of portfolios with nuclear generation; (b) assumptions about supply availability; and (c) frequency of pivotal evaluation. See the memo, "Differences in Pivotal Supplier Test Results in the IMM's and EMM's Annual Market Assessment Reports", NEPOOL Participants Committee Meeting, December 7, 2018.

power from New York. In addition, Long Island had further elevated energy prices because of major transmission outages of its tie lines with upstate New York, attracting more imports from Connecticut. These resulted in an average reduction of roughly 530 MW in net imports from New York in 2021.

Despite the slight increase in 2021, the pivotal supplier frequency has been falling in recent years. New market entry was a key driver in all New England, including more than 1.5 GW in 2018 and over 1 GW in 2019. In addition, price-responsive demand resources have been able to participate in the energy market since June 2018, satisfying a significant portion of reserve requirements. In Boston, the pivotal supplier frequency fell to less than 2 percent in both 2020 and 2021, much lower than the 28 percent in 2017. The entry of the Footprint power plant in 2018 has led to less frequent commitments of the Mystic facilities in the portfolio of the largest supplier in Boston. The increase in the import capability because of the Greater Boston Reliability Project upgrades has further reduced the reliance on the internal generation. Going forward, the three Mystic units (one steam turbine and two combined-cycle units) are expected to retire in the next couple of years, which will reduce internal supply for the Boston area. Although the reliability concern of these upcoming retirements has been studied and addressed through the transmission upgrades in the Boston Area Optimized Solution project, the pivotal supplier frequency in this area would likely rise.

In spite of the low pivotal supplier frequency in 2021, the results in Boston and all New England still warrant further review to identify potential withholding by suppliers in these regions. This review is provided in the following section, which examines the behavior of pivotal suppliers under various market conditions to assess whether the conduct has been consistent with competitive expectations.

C. Economic and Physical Withholding

Suppliers that have market power can exercise it by economically or physically withholding resources as described above. We measure potential economic and physical withholding by using the following metrics:

- ***Economic withholding:*** we estimate an "output gap" for units that produce less output because they have raised their economic offer parameters (start-up, no-load, and incremental energy) significantly above competitive levels. The output gap is the difference between the unit's capacity that is economic at the prevailing clearing price and the amount that is actually produced by the unit.[26] This may overstate the potential economic withholding because some of the offers included in the output gap may reflect legitimate supplier responses to operating conditions, risks, or uncertainties.

26 To identify clearly economic output, the supply's competitive cost must be less than the clearing price by more than a threshold amount - $25 per MWh for energy and 25 percent for start-up and no-load costs.

- ***Physical withholding:*** we focus on short-term deratings and outages because they are more likely to reflect attempts to physically withhold than other types of deratings, since it is generally less costly to withhold a resource for a short period of time. Long-term outages typically result in larger lost profits in hours when the supplier does not have market power.

The following analysis shows the output gap results and short-term physical deratings relative to load and participant characteristics. The objective is to determine whether the output gap and/or short-term physical deratings increase when factors prevail that increase suppliers' ability and incentive to exercise market power. This allows us to test whether the output gap and short-term physical deratings vary in a manner consistent with attempts to exercise market power.

Because the pivotal supplier analysis raises potential competitive concerns in Boston and all New England, Figure 6 shows the output gap and short-term physical deratings by load level in these two regions. The output gap is calculated separately for:

- ***Offline quick-start units*** that would have been economic to commit in the real-time market (considering their commitment costs); and
- ***Online units*** that can economically produce additional output.

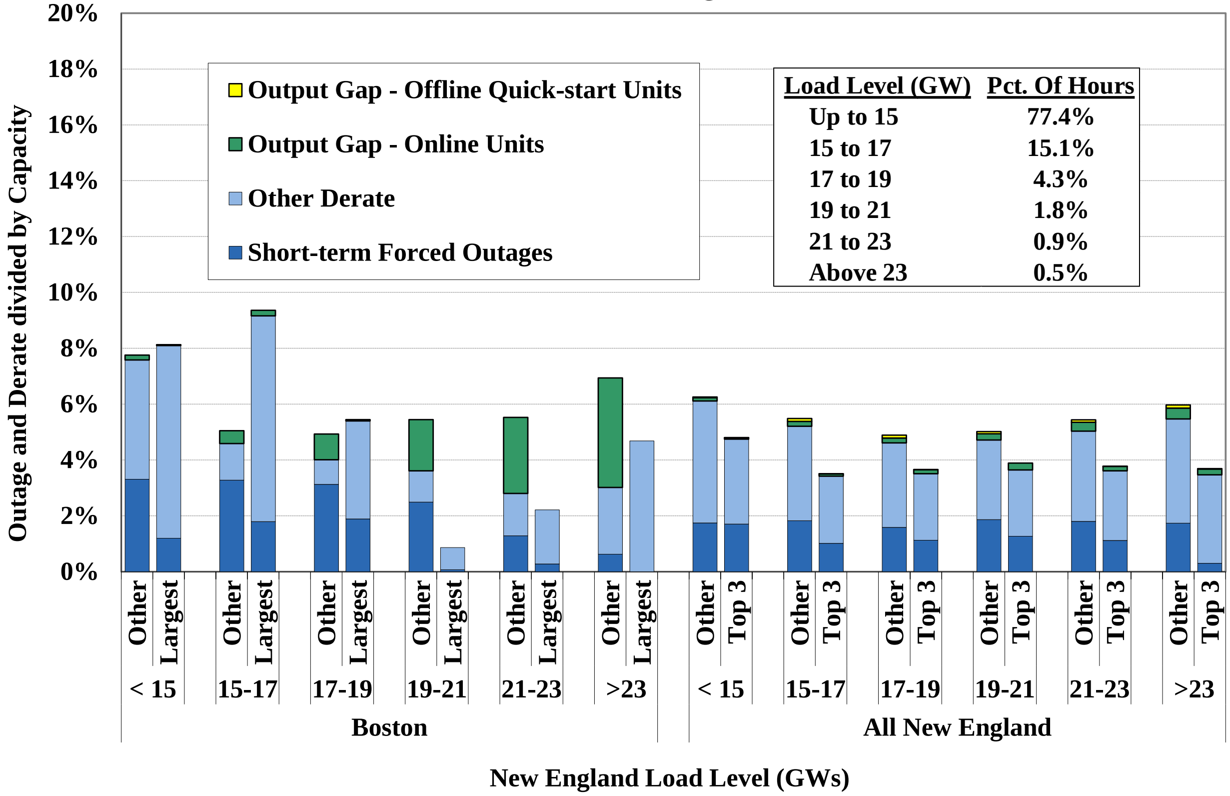
Our short-term physical withholding analyses examine:

- ***Short-term forced outages*** that typically last less than one week; and
- ***Other derates*** that includes reductions in the hourly capability of a unit that is not logged as a forced or planned outage. This can be the result of ambient temperature changes or other legitimate factors.

The results in Figure 6 are shown as a percentage of suppliers' portfolio size for the largest suppliers versus the other suppliers. In Boston, we include only the largest supplier in this comparison, who owned 64 percent of internal generating capacity in 2021. In all New England, we compare the three largest suppliers, who collectively owned 26 percent of internal generating capacity in 2021, to all other suppliers.

Figure 6 shows that the amount of "Other Derate" was usually higher than other categories. This was primarily because some combined-cycle capacity was often offered and operated in a reduced configuration during off-peak hours. This is generally efficient and does not raise significant competitive concerns. Additionally, the "Other Derate" category rose modestly for all classes of supplier during the highest load hours (above 23 GW). This was a very small number of hours during the summer when very high ambient temperatures tended to reduce the ratings of thermal generators.

Figure 6: Average Output Gap and Deratings by Load Level and Type of Supplier
Boston and All New England, 2021



Excluding the contributions of the "Other Derates" for the reasons described above, the overall output gap and deratings were not significant as a share of the total capacity in either Boston or all New England during 2021. The total amount of output gap and short-term deratings generally fell as load levels increased to the highest levels, which is a good indication that suppliers tried to make more capacity available when the capacity needs were the highest. In addition, the largest suppliers in all New England generally exhibited lower levels of overall output gap and deratings, particularly at higher load levels when prices are most sensitive to potential withholding.

In Boston, the small suppliers exhibited an increased output gap during high load conditions, most of which was associated with the duct-firing ranges of combined cycle capacity whose operating characteristics vary under high summer load conditions. However, this did not raise competitive concerns because: (a) it was from suppliers with small market shares in the area; and (b) it did not result in congestion and higher prices in Boston during these periods. The output gap continues to be very low across a wide range of conditions.

Overall, these results indicate that the energy market performed competitively in 2021 and did not raise significant concerns about withholding to raise market clearing prices.

D. Market Power Mitigation

Mitigation measures are intended to mitigate abuses of market power while minimizing interference with the market when it is workably competitive. The ISO-NE applies a conduct-impact test that can result in mitigation of a participant's supply offers (i.e., incremental energy offers, start-up and no-load offers). The mitigation measures are only imposed when suppliers' conduct exceeds well-defined conduct thresholds above a unit's reference levels and when the effect of that conduct on market outcomes exceeds well-defined market impact thresholds. This framework prevents mitigation when it is not necessary to address market power, while allowing high prices during legitimate periods of shortage.

The market can be substantially more concentrated in import-constrained areas, so more restrictive conduct and impact thresholds are employed in these areas than market-wide. The ISO has two structural tests (i.e., Pivotal Supplier and Constrained Area Tests) to determine which of the following mitigation rules are applied: [27]

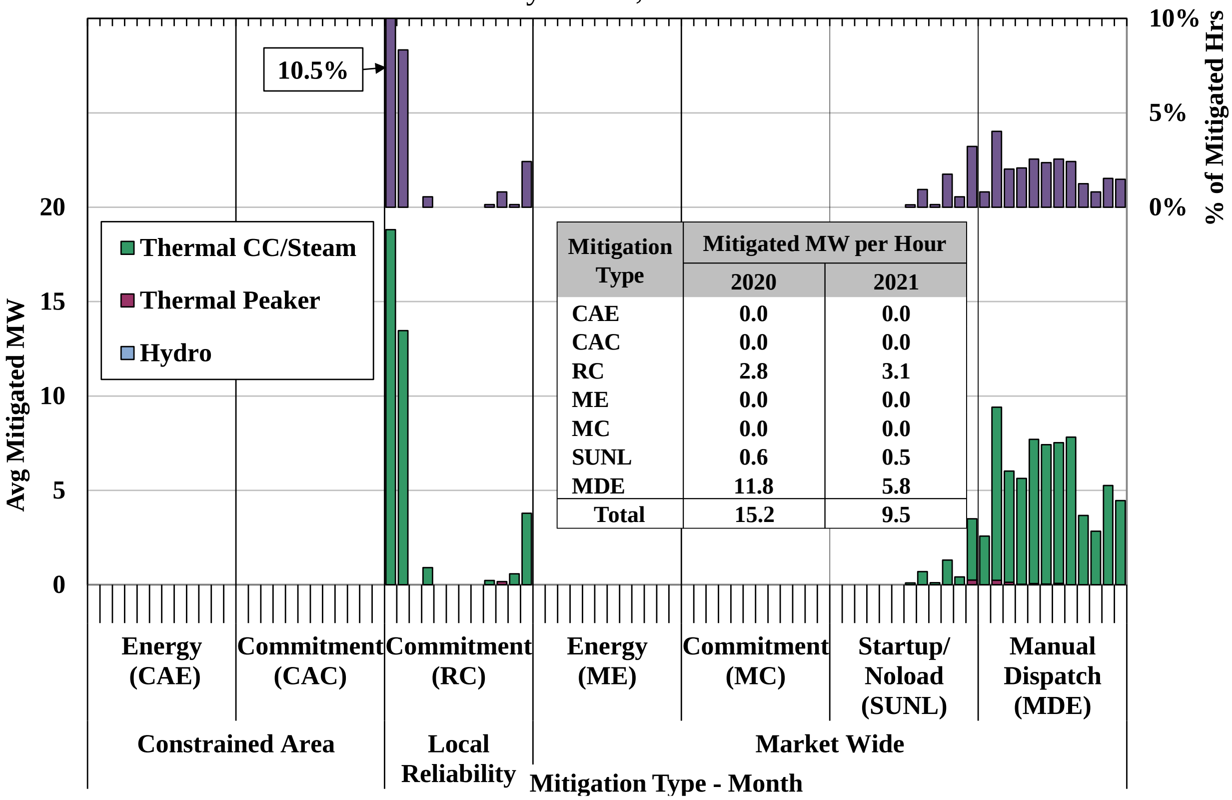
- Market-Wide Energy Mitigation (ME) – ME mitigation evaluates the incremental energy offers of online resources. This is applied to any resource whose Market Participant is a pivotal supplier.
- Market-Wide Commitment Mitigation (MC) – MC mitigation evaluates commitment offers (i.e., start-up and no-load costs). This is applied to any resource whose Market Participant is a pivotal supplier.
- Constrained Area Energy Mitigation (CAE) – CAE mitigation is applied to resources in a constrained area.
- Constrained Area Commitment Mitigation (CAC) – CAC mitigation is applied to a resource that is committed to manage congestion into a constrained area.
- Local Reliability Commitment Mitigation (RC) – RC mitigation is applied to a resource that is committed or kept online for local reliability.
- Start-up and No-load Mitigation (SUNL) – SUNL mitigation is applied to any resource that is committed in the market.
- Manual Dispatch Mitigation (MDE) – MDE mitigation is applied to resources that are dispatched out of merit above their Economic Minimum Limit levels.

There are no impact tests for the SUNL mitigation, the MDE mitigation, and the three types of commitment mitigation (i.e., MC, CAC, and RC), so suppliers are mitigated if they fail the conduct test in these five categories. This is reasonable because this mitigation normally only affects uplift payments, which usually rise as offer prices rise, so, in essence, the conduct test is serving as an impact test as well for these categories. When a generator is mitigated, all offer cost parameters are set to their reference levels for the entire hour.

[27] See Market Rule 1, Appendix A, Section III.A.5 for details on these tests and thresholds.

Figure 7 examines the frequency and quantity of mitigation in the real-time energy market during each month of 2021. Any mitigation changes made after the automated mitigation process were not included in this analysis (because these constitute a very small share of the overall mitigation). The upper portion of the figure shows the portion of hours affected by each type of mitigation. If multiple resources were mitigated during the same hour, only one hour was counted in the figure. The lower portion of the figure shows the average mitigated capacity in each month (i.e., total mitigated MWh divided by total numbers of hours in each month) for each type of mitigation and for three categories of resources: hydroelectric units, thermal peaking units, and thermal combined cycle and steam units. The inset table compares the annual average amount of mitigation for each mitigation type between 2020 and 2021.

Figure 7: Frequency of Real-Time Mitigation by Mitigation Type and Unit Type
By Month, 2021



Mitigation Type	Mitigated MW per Hour	
	2020	2021
CAE	0.0	0.0
CAC	0.0	0.0
RC	2.8	3.1
ME	0.0	0.0
MC	0.0	0.0
SUNL	0.6	0.5
MDE	11.8	5.8
Total	15.2	9.5

Mitigation has been infrequent in recent years, occurring in less than 4 percent of all hours in 2021, down modestly from 2020. Nearly all mitigation in the real-time market was for either local reliability commitment or manual dispatch energy. The high proportion of mitigation in these categories is expected because local reliability areas raise the most significant potential market power concerns and are mitigated under the tightest thresholds.

In general, these two categories of mitigation only affect NCPC payments and have little impact on energy or ancillary service prices. The occurrence of manual dispatch energy mitigation fell from 2020 to 2021, the vast majority of which was on combined-cycle units that were typically instructed to provide regulation service or to address transient issues on the transmission grid.

Although local reliability mitigation has the tightest threshold (10 percent) among all types of mitigation, it is not fully effective because suppliers sometimes have the latitude and incentive to operate in a more costly mode and receive larger NCPC payments as a result. For example, combined-cycle units needed for reliability that can offer in a multi-turbine configuration or in a single-turbine configuration often do not offer in the single-turbine configuration when they are likely to be needed for local reliability. By offering in a multi-turbine configuration, these units receive higher NCPC payments. We discuss this issue in more detail in Section III and continue to recommend that the ISO consider tariff changes that would expand its authority to address the issue.

The appropriateness of mitigation depends on accurate generator cost estimates (i.e., "reference levels"). If reference levels are too high, suppliers may be able to inflate prices and/or NCPC payments above competitive levels. If reference levels are too low, suppliers may be mitigated below cost, which could suppress prices below efficient levels. It can be difficult to estimate costs accurately for several types of generators, including:

- *Energy-limited hydroelectric resources*. The units' costs are almost entirely opportunity costs (the trade-off of producing more now and less later). These costs are generally difficult to accurately reflect.
- *Oil-fired resources*. They become economic when gas prices rise above oil prices. But when they have limited on-site oil inventory, the suppliers may raise their offer prices to conserve the available oil in order to produce during the periods with potentially the highest LMPs.
- *Gas-fired resources during periods of tight gas supply*. Volatile natural gas prices, particularly in the winter, create uncertainty regarding fuel costs that can be difficult to reflect accurately in offers and reference levels. The uncertainty is increased by the fact that offers and reference levels for the day-ahead market must be determined by 10 am on the prior day.

Appropriately recognizing opportunity costs in resources' reference levels reduces the potential for inappropriate mitigation of competitive offers, helps the region conserve limited fuel supplies, and improves the overall efficiency of scheduling for fuel-limited resources. ISO-NE uses a model to estimate an opportunity cost for oil-fired and dual-fuel generators with short-term fuel supply limitations to include in their reference prices. The model estimates opportunity costs by forecasting the profit-maximizing generation schedule for each unit with limited fuel supply over a rolling seven-day period and the opportunity cost adder ("Energy Market Opportunity Cost" or "EMOC") that would be required to limit its generation accordingly.

E. Competitive Performance Conclusions

The pivotal supplier analysis suggests that structural market power concerns have diminished noticeably in Boston and in all New England since 2018 because of:

- The new entry of more than 2.5 GW of generating capacity since 2018;
- Transmission upgrades in Boston; and
- Downward-trending load levels due to energy efficiency improvements and behind-the-meter solar generation. Relatively mild weather conditions and the effects of the COVID-19 pandemic also contributed to falling load levels.

Overall, we find little evidence of structural market power in all of New England or in individual sub-regions. Our analyses of potential economic and physical withholding also find that the markets performed competitively with no significant evidence of market power abuses or manipulation in 2021.

In addition, we find that the market power mitigation rules have generally been effective in preventing the exercise of market power in the New England markets. The automated mitigation process helps ensure the competitiveness of market outcomes by mitigating attempts to exercise market power in the market software before it can affect the market outcomes. To ensure competitive offers are not mitigated, generators can proactively request reference level adjustments when they experience input cost changes due to fuel price volatility or other factors. Hourly offers enable generators to modify their offers to reflect changes in their marginal costs and for the ISO to set reference levels that properly reflect these costs.

Nonetheless, we find one area where the mitigation measures may not have been fully effective. This relates to resources that are frequently committed for local reliability. Although the mitigation thresholds are tight for these resources, the suppliers have the incentive to operate in a higher-cost mode and receive higher NCPC payments as a result. This is discussed in more detail in Section I. Hence, we recommend the ISO require resources to operate in the lowest-cost configuration when they are committed for local reliability.

III. Out-of-Market Commitments and Operating Reserve Markets

To maintain system reliability, sufficient resources must be available in the operating day to satisfy forecasted load and operating reserve requirements, both at the system level and in local load pockets. The day-ahead market is intended to provide incentives for market participants to make resources available to meet these requirements at the lowest cost. Satisfying reliability requirements in the day-ahead market is more efficient than waiting until after the day-ahead market clears because reliability commitments affect which resources should be committed economically in the day-ahead market.

The ISO commits resources within the day-ahead market scheduling process to satisfy two types of reliability requirements not embodied in the day-ahead market products. They are to:

- Ensure the ISO is able to reposition the system in key areas in response to the second largest contingency after the first largest contingency has occurred; and
- Satisfy system-level operating reserve requirements.

These commitments are made outside of the market (OOM) because they are not reflected in ISO-NE's market products, causing the clearing prices of energy (and reserves) are understated because they do not reflect the costs of satisfying these requirements. When resources are scheduled at clearing prices that are not sufficient for them to recoup their full as-bid costs, ISO-NE provides an NCPC payment to cover the revenue shortfall.

Although total NCPC costs are small relative to the overall market costs, they are important because they usually occur when the market requirements are not fully aligned with the system's reliability needs, or when prices are otherwise not fully efficient. This alignment is key for causing the wholesale market to provide efficient short-term operating incentives and long-term investment incentives to satisfy the system's needs. Efficient incentives for flexible low-cost providers of operating reserves will be increasingly important as the penetration of intermittent renewable generations increases over the coming decade.

This section evaluates these reliability commitments and resultant NCPC charges and discusses implications for market efficiency. It is divided into subsections that address commitment for: a) system-level operating reserve requirements, and b) local second contingency protection requirements. The final subsection summarizes of our conclusions and recommendations.

A. Day-Ahead Commitment for System-Level Operating Reserve Requirements

The day-ahead market software commits sufficient resources to satisfy system-level operating reserve requirements in addition to bid load. However, these reserve requirements are not enforced as a market product in the day-ahead market dispatch or pricing software because ISO-NE does not have day-ahead reserve markets. Consequently, generators are frequently committed in the day-ahead market to satisfy reserve requirements, but are not scheduled or paid to provide reserves. As a result, the clearing prices of energy (and reserves) are understated because they do not reflect the costs of satisfying the reserve requirements.

Table 3 summarizes the additional commitments to satisfy the system-level 10-minute spinning reserve requirements in the past three years by showing our estimates of:

- The total number of hours in each year during which such commitments occurred;
- The average capacity (i.e., the Economic Max of the unit) committed in these hours;
- The total amount of NCPC uplift charges incurred; and
- The annual average marginal value of 10-minute spinning reserves that was not reflected in the day-ahead market clearing prices.

Table 3: Day-Ahead Commitment for System 10-Minute Spinning Reserve Requirement
2019 - 2021

Year	# Hours	Average Capacity Committed per Hour (MW)	DA NCPC (Million $)	Average Reserve Value ($/MWh)
2019	3774	580	$4.2	$2.21
2020	4054	571	$3.8	$1.68
2021	3389	514	$5.4	$1.94

The table shows that additional generating capacity was committed to satisfy the system-level 10-minute spinning reserve requirement in 39 to 46 percent of hours in each of the past three years. This was the second largest contributor to the NCPC uplift charges in the day-ahead market during the period. Co-optimized procurement and pricing of this reserve product in the day-ahead market would improve the pricing of both 10-minute spinning reserves and energy since this would lead the opportunity cost of not providing reserves to be reflected in the price of energy. We estimate that the absence of a day-ahead 10-minute spinning reserve product reduced energy prices across the system by an average of nearly $2 per MWh over the past three years.[28] We also estimate that pricing such a product would increase the energy and ancillary services net revenues for a 4-hour battery storage unit by $18 per kW-year.[29]

Setting more efficient prices for energy and spinning reserves would provide better incentives for reliable performance, flexibility, and availability. Under-compensating generators that have flexible characteristics will be increasingly undesirable as the penetration of intermittent renewable generation increases over the coming decade because these resources will be essential

28 These estimates quantify the direct effect of modeling the reserve requirements in the day-ahead market. However, the increase in day-ahead LMPs would attract additional virtual supply, which would reduce the LMP effect, while increasing the effect on 10-minute spinning reserve prices.

29 See Section IV.B of our 2020 SOM Annual Report.

to complement the intermittent resources and maintain reliability. Therefore, we recommend the ISO procure operating reserves in the day-ahead market, as discussed further below.

B. Day-Ahead Commitment for Local Second Contingency Protection

Most reliability commitments for Local Second Contingency Protection (LSCP) occur in the day-ahead market. While these commitments may be justified from a reliability perspective, the underlying local requirements are not enforced in the day-ahead market pricing software. As a result, they can lead to inefficient prices and concomitant NCPC uplift. Most NCPC charges for local reliability commitments are incurred in the day-ahead market rather than the real-time market, as is the case for most other RTOs. These local commitments have been the largest contributor to NCPC charges in the day-ahead market in the recent years.

Table 4 summarizes the commitments for local second contingency protection in the day-ahead market from 2019 to 2021 by showing:

- The total number of days in each year with such commitments;
- The total number of hours in each year with such commitments;
- The average capacity (i.e., the Economic Max of the unit) committed over these hours;
- The total amount of NCPC uplift charges incurred;
- The NCPC uplift charge rate (i.e., NCPC uplift per MWh of committed capacity); and
- The implied marginal value of local reserves that was not reflected in market clearing prices aggregated over the year.

Table 4: Day-Ahead Commitment for Local Second Contingency and NCPC Charges
2019 – 2021

Year	LSCP Region	# LSCP Days	#LSCP Hours	Average LSCP Capacity per Hour (MW)	DA NCPC (Million $)	Average Uplift Rate ($/MWh)	Implied Marginal Reserve Value ($/kW-Year)
2019	**NH Seacoast**	33	296	46	$0.4	$28.93	$8.57
	NH-to-Maine	68	1035	370	$2.5	$6.58	$9.21
	NEMA/Boston	4	42	600	$0.2	$7.37	$0.31
	Lw. SEMA & East RI	51	696	292	$2.6	$12.94	$11.74
	WMASS Springfield	5	38	273	$0.2	$15.84	$0.60
	NE West-to-East	15	164	355	$0.2	$3.00	$0.62
2020	**NH Seacoast**	3	38	45	$0.04	$21.91	$0.80
	NH-to-Maine	28	401	298	$2.0	$16.92	$8.24
	NEMA/Boston	7	72	672	$0.7	$14.27	$0.97
	Lw. SEMA & East RI	24	245	232	$0.2	$4.28	$1.72
	NE West-to-East	51	553	373	$0.8	$3.85	$3.03
2021	**NH-to-Maine**	38	510	311	$1.6	$10.22	$8.11
	NEMA/Boston	4	42	651	$0.4	$14.31	$0.55
	Lw. SEMA & East RI	9	61	244	$0.1	$7.01	$1.05
	NE West-to-East	52	683	639	$3.5	$8.07	$6.55

The table above shows these values for each import-constrained area for which LSCP commitments were made in the day-ahead market. The implied marginal reserve values are additive for areas that are nested within a broader import-constrained area.[30] The most notable results over the past two years are in two areas:

- *Eastern New England.* Day-ahead commitments for local second contingency protection in the broader region east of the New England West-to-East interface were most frequent in 2021, occurring on 52 days (nearly 700 hours) and accounting for 56 percent of NCPC uplift in this category. Most of these commitments occurred during periods when planned transmission outages reduced the transfer capability across the West-to-East interface.
- *Maine*. Although Maine generally exports to other areas, operating reserves are still required to ensure local reliability in case two large contingencies occur. Reliability commitments in this area were frequent as well, often occurring in the shoulder months when transmission maintenance outages reduce import capability from New Hampshire.

Day-ahead commitments for local second contingency protection in other areas have fallen in recent years, largely because reliability transmission upgrades in these areas. For example, local second contingency protection commitments in the combined area of Lower SEMA and Eastern Rhode Island have fallen from 51 days in 2019 to just 9 days in 2021. This is attributable to recent transmission upgrades associated with the Southeast Massachusetts/Rhode Island Reliability Project. Similarly, the reliability commitments for the small Seacoast load pocket in New Hampshire rarely occurred in 2020 and 2021 because of transmission upgrades associated with the New Hampshire Solution – Seacoast Reliability Project.

In 2021, the uplift cost per MWh of committed capacity ranged from roughly $7 per MWh in the combined area of Lower SEMA and Eastern Rhode Island to $14 per MWh in the NEMA/Boston load pocket. These results raise two significant efficiency concerns:

- First, the units receiving NCPC payments, which tend to be higher-cost and less flexible, systematically receive more revenues than lower-cost resources that generally do not require NCPC payments.
- Second, the costs of the resources receiving NCPC payments are not reflected in operating reserve prices paid to other resources that help satisfy the same underlying reliability requirement.

These two inefficiencies distort economic incentives in favor of higher-cost, less flexible units and lower prices received by all other units. The final column in the table shows that if all reserves providers in the area received the implied marginal value of local reserves, it would increase the estimated net revenue received by a fast start unit in 2021 by:

- Over $6.5 per kW-year in eastern New England (east of the West-to-East interface); and

30 For example, the NE West-to-East interface defines an import-constrained region that includes Central Mass, SE Mass, NEMA/Boston, Rhode Island, New Hampshire, and Maine. So, the implied marginal reserve value for a unit in Maine would be $14.66/kW-year in 2021 ($8.11 of NH-to-Maine plus $6.55 of NE West-to-East).

- Nearly $15 per kW-year in Maine.

These values represent a sizable increase in net revenue given that such units earned an estimated $26 per kW-year under the current markets in 2021. The frequent use of out-of-market NCPC payments highlights the need for market reforms to improve the efficiency of prices for energy and operating reserves in local areas. Satisfying local requirements through a day-ahead operating reserve market would substantially reduce the need to commit resources out-of-market in the local areas that currently receive sizable NCPC payments. These concerns are exacerbated by two issues that lead excessive amounts of capacity to be committed for local second contingency protection when additional reserves are needed.

Multi-Turbine Configuration. Some generators that are frequently committed for local second contingency protection offer as a multi-turbine group, requiring the ISO to commit multiple turbines when one turbine would be sufficient. Needlessly committing the multi-turbine configuration displaces other more efficient generating capacity. In 2021, multi-turbine combined-cycle commitments accounted for: (a) roughly 46 percent of the capacity committed for local reliability in the day-ahead market; and (b) roughly 57 percent of day-ahead local second contingency NCPC payments.

The ISO could avoid excess commitment by modifying its tariff to require capacity suppliers to offer multiple unit configurations to allow the ISO the option of committing just one turbine at a multi-turbine group. This would improve market incentives for flexibility and availability.

Treatment of Imports. Day-ahead scheduled energy imports from neighboring areas are currently not counted towards satisfying local second contingency protection needs in the same manner as energy scheduled on internal resources—even if the import is associated with a CSO.

- In 2021, an average of 182 MW of net imports from New Brunswick were scheduled in the day-ahead market on the days when LSCP commitments occurred either for the New Hampshire-to-Maine interface or the New England West-to-East interface.
- Allowing these imports to satisfy local second contingency requirements would have reduced the need for LSCP commitments by 11 percent.
- However, given the lack of a day-ahead reserve market with a comprehensive set of local requirements, firm importers that satisfy local requirements are not compensated efficiently.

C. Conclusions and Recommendations

In our assessment of day-ahead reliability commitment in 2021, we found that 75 percent of the day-ahead NCPC or almost $12 million was incurred to satisfy the system-level 10-minute spinning reserve requirement or local second contingency requirements in more than 4600 hours.

Because the commitments to satisfy these requirements are made outside of the market, they depress day-ahead energy prices and require NCPC payments to cover their costs.

As a result, resources that contribute to satisfying these needs are undervalued, as is energy more broadly. Because the ISO does not procure the reserves it will need in the day-ahead market, a large share of its operating reserves needed to satisfy NERC and NPCC criteria are supplied by resources receiving no day-ahead reserve schedules or related compensation – "latent reserves". This is problematic because:

- Many of these resources have energy limitations that would prevent them from converting reserves to energy for significant periods; and
- Others rely on pipeline gas that is not always available on short notice.
- Hence, their availability is less certain than resources that are procured in the day-ahead market. This concern may become more acute as the resource mix shifts toward relying more on short-duration battery storage.

Therefore, we recommend that the ISO implement operating reserve requirements in the day-ahead market that are co-optimized with energy. This should include operating reserves needed to satisfy both the local second contingency requirements and systemwide forecasted energy and reserve requirements.[31] Procuring and pricing these requirements in the day-ahead market would result in substantial additional net revenues, especially for flexible resources such as fast-starting peaking units and battery storage units that will be helpful for integrating intermittent renewable generation. The ISO is evaluating potential solutions to this recommendation in its *Day-Ahead Ancillary Services Improvements* project, and we strongly support this effort. To address its local reliability needs, it should consider approaches that would allow it to dynamically define new reserve zones as second contingency protection requirements arise in different areas.

Lastly, we continue to find that out-of-market commitment and NCPC costs are inflated because: (a) the ISO is often compelled to start combined-cycle resources in a multi-turbine configuration when its reliability needs could have been satisfied by starting them in a single-turbine configuration; and (b) the ISO does not allow firm energy imports to satisfy local second contingency requirements and thereby reduce the associated local reserve requirements. To address these concerns, we recommend that the ISO:

- Expand its authority to commit combined-cycle units in a single-turbine configuration when that will satisfy its reliability need (Recommendation #2014-5); and
- Consider allowing firm imports from neighboring areas to contribute towards satisfying local second contingency requirements (Recommendation #2020-1).

[31] Recommendation #2012-8 would co-optimized reserves in the day-ahead market, while Recommendation #2019-3 implement a comprehensive set of local operating reserve requirements in the day-ahead and real-time markets.

IV. Assessment of Forward Capacity Market Design

The capacity market is the primary market-based mechanism for satisfying resource ISO-NE's resource adequacy requirements, which are designed to ensure a minimum reliability standard of no more than 1 day of load shedding every 10 years. ISO-NE operates a centralized auction framework in which suppliers compete to obtain capacity supply obligations (CSOs) in exchange for payments at the auction clearing price. The capacity market provides incentives for efficient entry of new capacity that is needed for reliability and the retirement of surplus capacity.

New England's power sector is experiencing profound changes that will make the task of efficiently satisfying resource adequacy requirements more challenging, including:

- Large-scale entry of state-sponsored resources that receive a combination of wholesale market revenues and out-of-market revenues,
- Growing reliance on intermittent and energy-limited resources with complex characteristics that limit their availability, and
- Increased awareness of limitations faced by the generation fleet during extreme weather, especially in winter months.

Current capacity market rules were designed assuming that the vast majority of capacity would be supplied by conventional generators that are available year-round at all hours of the day, and that entry and exit would be mainly driven by market prices. However, as the characteristics and incentives for new generation investment change, the capacity market rules must evolve accordingly. This section highlights several features of the capacity market that should be adapted to these new circumstances:

- Section A discusses the need to update ISO-NE's reliability planning models and the capacity credit assigned to suppliers, so that capacity payments accurately reflect the marginal value of reliability provided by each resource.
- Section B analyzes how efficient capacity accreditation techniques might be applied to generators that rely on pipeline gas during peak winter conditions and discusses the need for market signals to differentiate between the value of capacity in summer and winter seasons.
- Section C assesses the forward capacity market framework, in which loads must procure capacity over three years in advance. This section discusses why the FCA is not structured to satisfy reliability needs efficiently and contrasts it with a "prompt" market framework that would procure capacity closer to the commitment period.
- Section D evaluates the need to revise the Net CONE value used in the capacity demand curve to account for financial risks to merchant suppliers that are posed by state policies.
- Section E provides a summary of our conclusions and recommendations for improving capacity market design.

A. Resource Adequacy Modeling and Efficient Capacity Accreditation

ISO-NE's current practices do not accurately assess the reliability contributions of individual resources or the resource adequacy of the system as a whole. This is because: (1) simplistic methods are used to determine resources' capacity credit that do not reflect the marginal reliability benefit they provide, and (2) ISO-NE relies on a resource adequacy model that assumes an excessively high availability for some resources during tight conditions. These issues are closely related because efficient capacity accreditation requires an accurate resource adequacy model. As a consequence, the FCA does not send efficient signals for resources to enter and exit the market and may fail to procure the resources needed for reliability.

Efficient Capacity Accreditation

Capacity credit refers to the amount of megawatts a resource may offer and be compensated for in capacity market auctions. In ISO-NE, a resource that participates in the Forward Capacity Market may obtain a Capacity Supply Obligation (CSO) up to its Qualified Capacity (QC) rating. Generally, this rating is determined based on the resource's tested maximum output (for conventional generators) or its seasonal median output during certain hours of the day (for intermittent resources).[32]

In an efficient market, capacity credit reflects a resource's marginal contribution to reliability. This is equivalent to the impact that an incremental quantity of that resource type would have on the system's reliability. Capacity credit based on marginal value provides efficient incentives by paying each resource in proportion to the change in system reliability that would occur if the resource were to enter the market or retire. Alternative approaches that deviate from marginal value (such as simple heuristics or 'average' accreditation) are inefficient because they misalign resource owners' compensation from the impacts of their actions.[33]

ISO-NE's methods to determine QC largely rely on simple heuristics and are likely to significantly differ from marginal reliability contribution for the following resource types:

Intermittent Resources: The QC of intermittent generators such as wind and solar is determined based on their median output across certain hours each day in the winter and summer seasons.[34] This reflects typical output in the timeframes when peak loads have historically occurred.

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32 For most resource types, maximum Qualified Capacity is based on Seasonal Claimed Capability (SCC). See ISO-NE, *Having a Capacity Supply Obligation Lesson 2C: Introduction to Capacity Resources*.

33 We discuss the difference between capacity accreditation based on marginal value and alternative approaches that have been proposed in other markets (such as average or portfolio ELCC) in the Appendix Section VII.

34 Output is measures during hour ending 14 through 18 in the Summer season (June through September), and hour ending 18 through 19 in the Winter season (October through May), plus any reserve shortage hours.

However, it does not account for correlation of output from resources of the same technology or location. As penetration of these resources grows, the timing of reliability needs will shift to hours when they are less likely to be available. As a result, the current approach to determine their QC will increasingly overestimate their marginal reliability value.

Energy Storage: Energy limited resources, such as battery storage, can produce output for a limited period of time. As a result, the reliability value of such resources is lower than that of a resource that can generate indefinitely. The marginal reliability value of storage depends on the number of hours it can run, the penetration levels of other storage resources with various durations, and factors such as penetration of intermittent renewables (which tends to increase the marginal reliability value of storage).

Under current rules, storage that can discharge for at least two hours may offer QC up to 100 percent of its installed capacity in the FCM. This allows low-duration batteries (such as two-hour systems) to receive compensation that far exceeds their true reliability value.[35] As a result, the FCM provides little incentive for developers to choose longer-duration storage projects (which are more reliable but more costly) over short-duration batteries with diminishing benefits.

Pipeline Gas Dependency: Units that rely on common fuel supplies (such as a single shared pipeline) and do not have alternative backup fuels provide less reliability value than units that are not dependent on a common fuel source in two ways. First, extreme weather could limit the total fuel available to a group of units with no alternative fuel source, reducing the available output from the group. Second, an outage of gas pipeline equipment could result in several units being unavailable simultaneously from a single contingency. Currently, these risks are not accounted for in the determination of QC, which is based on Seasonal Claimed Capability (tested maximum output) for thermal generators.

Large Size: A large individual unit provides less reliability value than several smaller units that add up to the capacity of the large unit. This is because several small units are unlikely to experience forced outages simultaneously, while the outage of a large unit is more likely to affect reliability.[36] Currently, this is not accounted for in the QC of individual resources.

Low Flexibility: Some units (e.g., older steam turbines) require lengthy advanced notice because of long startup lead times that reduce operational flexibility. If such a unit is not already online or committed, it may not be able to provide output if a period of critical system need occurs with short notice. Hence, inflexible units with low capacity factors have less reliability value than more flexible units. This is not accounted for in a unit's QC.

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35 For example, in a past report analyzing the NYISO system, we found that the capacity value of a 2-hour battery storage resource was 66 to 68 percent when the overall penetration of storage resources is 500 MW, declining to 38 to 41 percent at 2,000 MW of penetration.

36 See Section V.C of our 2019 Assessment of the ISO-NE Electricity Markets.

Shortcomings of Resource Adequacy Model

ISO-NE uses the resource adequacy model GE-MARS to determine its Installed Capacity Requirement (ICR). Hence, each resource type should be modeled accurately in MARS so that the ICR satisfies the target level of reliability. Furthermore, accurate representation in MARS will be needed to calculate the marginal reliability contributions of individual resource types.

MARS is used to assess system reliability, measured in terms of Loss of Load Expectation (LOLE). It performs a probabilistic Monte Carlo simulation of resources' availability to serve load in each hour of the year, considering uncertainty in the annual load forecast and random outages of individual units. If the resource mix is less reliable on average, this process will result in a higher ICR to account for uncertainty in resources' availability. When running MARS to determine the ICR, ISO-NE assumes that all capacity suppliers are available up to their Qualified Capacity unless experiencing a random outage or scheduled maintenance. MARS assumes all available capacity is fully committed at all times and, therefore, does not account for the ISO's actual chronological commitment decisions or day-ahead forecast uncertainty.

The availability of several resource types is currently overestimated in MARS. The table below describes the current modeling of these resource types and potential improvements:

Table 5: Modeling Issues for Resource Types in MARS

Resource Type	Current modeling approach	Improved modeling approach
Intermittent resources	Available up to QC rating in all hours, no variation in hourly output	Model hourly resource profile reflecting weather patterns and technology characteristics. Align with weather year underlying load profile
Pipeline gas generators	Available up to QC rating in all hours unless experiencing random forced outage	Limit output of pipeline gas generators based on maximum shared gas availability in winter
Energy limited resources	Storage modeled as energy limited resource, deployed to prevent load shedding if other resources are unavailable	Consider realistic timing of storage deployment in sequence of emergency operating procedure (EOP) steps such as external assistance and reserves
Inflexible generators	Available up to QC rating in all hours unless experiencing random forced outage[37]	Model unit commitment separately from dispatch with stochastic net load forecast errors between stages; treat unit as unavailable if not committed

37 Modeling commitment separately from dispatch may require fundamental changes to MARS. We encourage ISO-NE to explore whether this is possible but note that inflexible generators are especially vulnerable to pay-for-performance (PFP) penalties when flexibility-driven reserve shortages occur.

B. Efficient Capacity Accreditation for Non-Firm Gas Generators

Generators that rely on pipeline gas and lack dual fuel capability ("gas-only") are not modeled accurately in ISO-NE's resource adequacy model and are not assigned capacity values consistent with their marginal reliability value. In the most recent FCA for the capability period 2025-26, ISO-NE awarded CSOs to 8 GW of gas-only generators. Hence, this is currently the largest class of resources whose marginal reliability value may significantly differ from the credit they are assigned in the FCM. This subsection analyzes the historical output of pipeline gas generators during winter peak conditions and the factors affecting their marginal reliability value.

Marginal Reliability Value of Pipeline Gas-Dependent Generation

New England does not produce natural gas locally and relies on gas imported through interstate pipelines to supply fuel for winter heating, power generation, and other uses. Most firm transportation rights on the interstate pipelines are held by local gas distribution utilities (LDCs), so there is limited spare capacity available to supply power plants after gas heating demand is satisfied. Additional gas is available to generators from three liquified natural gas (LNG) import facilities which connect to the pipeline system serving New England (Everett and Northeast Gateway in Massachusetts and Saint John in New Brunswick, Canada). However, LNG import deliveries must be arranged far in advance and are not generally available on a spot basis.

Figure 8 estimates generators' use of gas delivered on interstate pipelines (which excludes gas from LNG imports). It shows the 30 winter days with the highest peak loads from December 2017 to February 2022. The gray shaded bars show injections of LNG into the New England pipeline system.[38] We assume that on winter days, gas is first used for LDCs' heating demand and that generators are served by any leftover pipeline gas and LNG. Hence, we estimate the pipeline gas used by power generators as their total gas consumption minus LNG imports. The days shown in Figure 8 are arranged in descending order of peak load, shown in the top panel. For the analyses in this subsection, gas consumption and LNG import values exclude LNG consumption by the Mystic 8 and 9 units, which obtain it directly via the Everett terminal.

Figure 8 shows that on the highest load days, the vast majority of power plant gas consumption has been made possible by LNG imports. On the top ten highest-load days in the past five winters, LNG accounted for nearly all gas-fired generation. The total amount of LNG imports varied on these days (with higher injections in 2019/2020 and lower injections in 2017/2018), corresponding to variations in the total amount of gas consumption by power plants.

38 LNG imports show the injections from the Everett, Northeast Gateway, and the St. John terminal after netting gas consumption in Canada. The bars show imports via the Everett and Northeast Gateway to the Algonquin Pipeline but do not include LNG provided directly to the Mystic plant and other local off-takers. Net imports from the St. John facility in New Brunswick reflect flows into New England via the Maritimes and Northeast Pipeline at the Baileyville station in Maine (deducting gas consumption in Canada). Pipeline receipt data was obtained from S&P Global.

Figure 8: Power Plant Gas and LNG Consumption on High Load Winter Days
December 2017 – February 2022

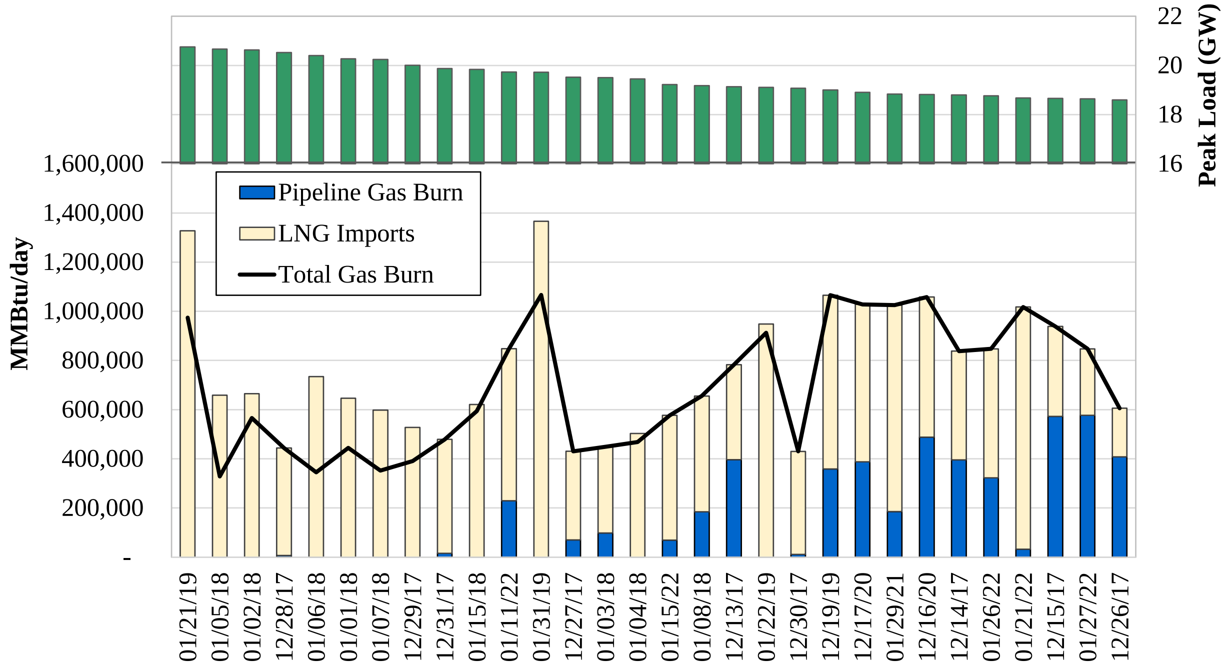

Figure 9 compares daily peak load with peak-hour generation from pipeline gas (excluding generation fueled by LNG) for the same 30 days as in Figure 8. Peak-hour pipeline gas generation is estimated as total peak output by gas-fired generators multiplied by the ratio of pipeline gas burn to total gas burn (including LNG) on that day. The orange and black lines show the forecasted 50/50 and 90/10 net peak load forecast for Winter 2022/23 from the 2022 CELT report (indicating that peak load has a 50 percent and 10 percent chance of exceeding these values, respectively).

Figure 9 shows that on high-load winter days there has been a negative relationship between peak load and generation supplied by pipeline gas (excluding LNG).[39] On days when load exceeded the 2022 CELT's winter load forecast of 20.0 GW, generation supplied by pipeline gas was minimal. This suggests a large portion of New England's gas-dependent generation will be unable to operate under the tightest winter conditions unless LNG imports are available. LNG has enabled some of these resources to operate in past winters as peak-hour gas generation on the top ten winter days has ranged from 2.7 GW to 7.1 GW. However, most gas generators do not secure contracts for firm LNG deliveries, and it is unknown how much LNG will be available in future cold weather events (beyond what LDCs need to satisfy their own planning criteria).

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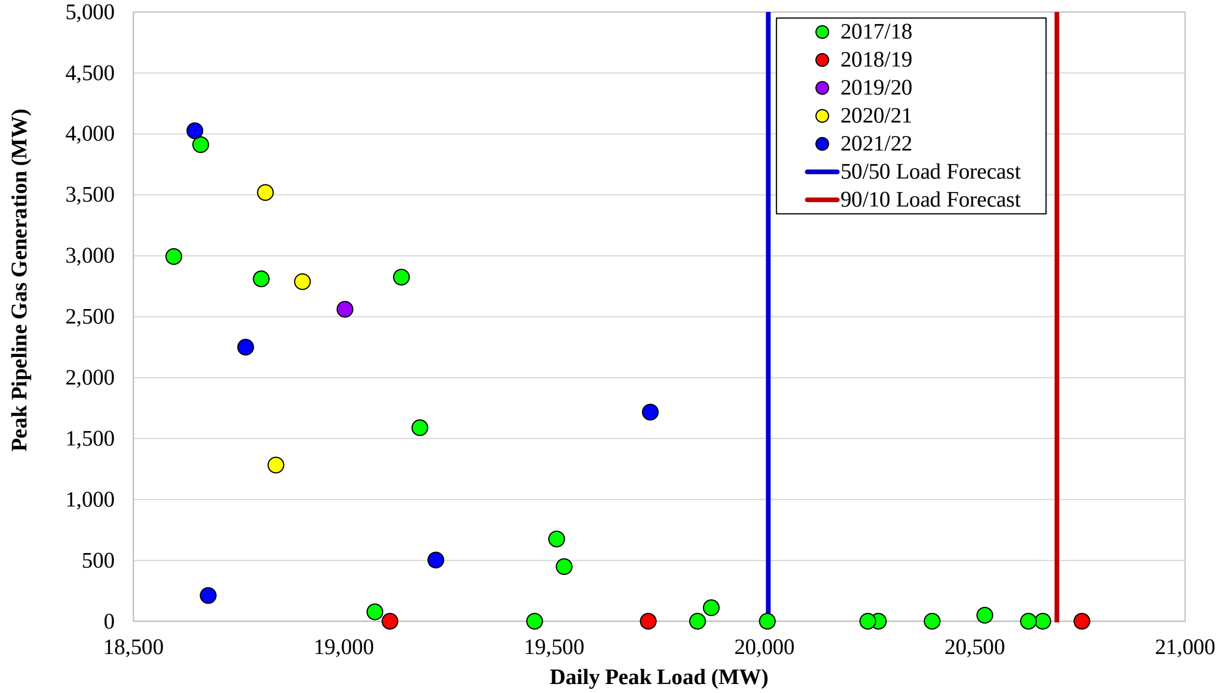
39 Note that changes in factors such as load patterns and energy efficiency over time may alter the peak load that would occur at a given temperature, potentially changing the relationship between load and available gas generation. Hence, this analysis is indicative, and a more robust calculation would make adjustments for forecasted changes in the relationships between temperature, load and heating gas demand.

Figure 9: Winter Peak Load vs. Pipeline Gas Generation
December 2017 – February 2022



The importance of these findings related to gas availability depends on whether tight gas system conditions coincide with the periods when the electric system conditions are tightest. Since its creation, ISO New England has been a summer peaking system, so the capacity market is designed to procure sufficient resources for the summer and, as a byproduct, this has also satisfied system needs during other seasons. However, as winter demand increases relative to summer demand and the generation mix includes more resources that are less available in the winter (e.g., solar and gas-only units), it will become more important to consider gas availability in the compensation of capacity resources. The following figure analyzes the value of these resources as New England shifts from a summer-peaking to a winter-peaking system.

Figure 10 shows two measures of capacity value for pipeline gas generators – marginal reliability improvement (MRI) and average effective load carry capability (ELCC). The quantity on the X-axis is the amount of pipeline gas-only capacity that does not have a contract for delivery of LNG. We estimated the MRI and ELCC values on the Y-axis using a simplified resource adequacy model that simulates expected unserved energy (EUE). At each level of pipeline-gas-dependent generation, the system is adjusted so that total EUE is equal to a criteria level (similar to the procedure used to determine the ICR).

Pipeline gas capacity that is not backed by LNG is assumed to be limited on high-load winter days, using a relationship based on the data shown in Figure 9. The bottom panel shows the percentage of annual EUE that occurs in winter months if the supply mix contains a given level of pipeline gas generation. This analysis only considers joint unavailability of pipeline gas generators due to constraints on the maximum amount of gas that can be transported through the interstate pipeline system. As noted in Section A, there is also a risk that pipeline gas resources will be jointly unavailable due to outage of gas infrastructure serving multiple plants. Accounting for this risk in the resource adequacy model would require assumptions regarding the probability of gas system contingencies.

Figure 10: Capacity Value Curve for Non-Firm Pipeline Gas Generators

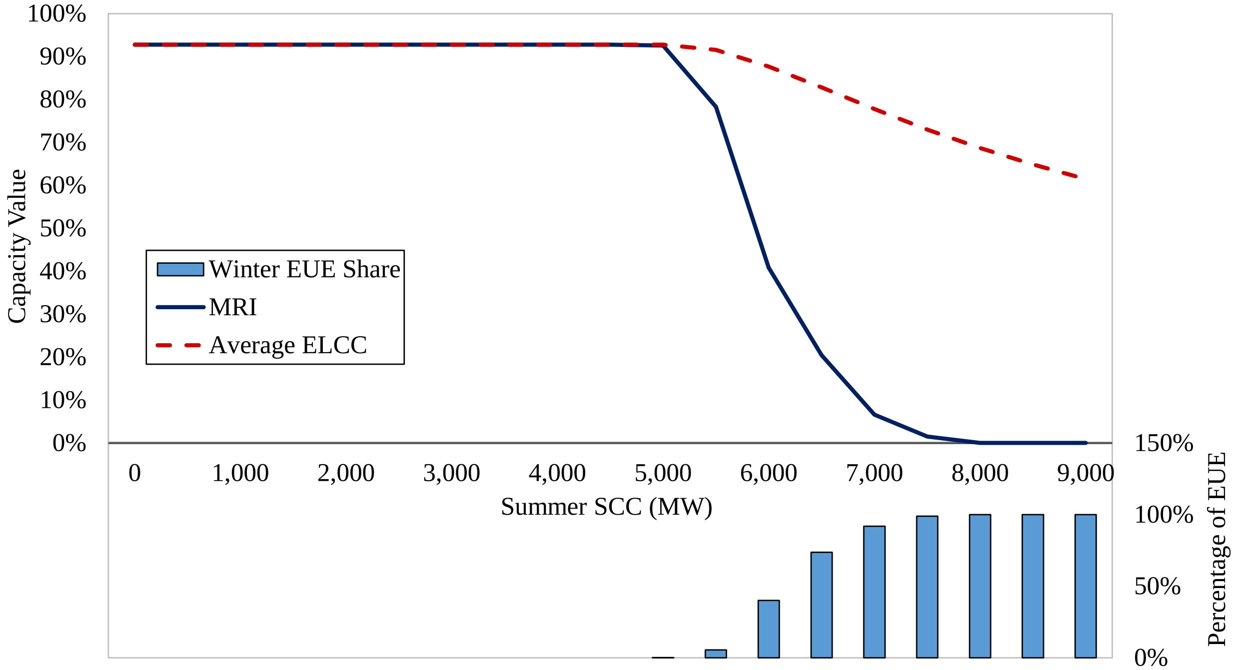


Figure 10 shows that when there is a large amount of pipeline gas capacity not backed by LNG, its marginal reliability value declines rapidly:

- For 8.0 GW of pipeline gas capacity without LNG, we estimate an MRI of **zero** percent.
- However, if the system was dependent on a smaller amount of pipeline gas generation (or if a significant portion of it was backed by LNG), its MRI would be much higher – over 90 percent at total penetrations of 5.0 GW or less.

Figure 10 also shows that the share of EUE taking place in winter months increases at higher penetrations of pipeline gas. In other words, reliability risks are increasingly concentrated in winter when the system's dependence on pipeline gas capacity is higher.[40]

This figure demonstrates that the marginal value of pipeline gas capacity is closely related to the proportion of load-shedding risk that takes place in winter. Pipeline gas generators have a high

40 It is important to note that this analysis does not necessarily imply that ISO-NE is currently at a heightened risk of load shedding in winter months. We calculated MRI and ELCC values 'at criteria' (e.g., assuming there is no capacity surplus beyond what is needed to satisfy minimum reliability requirements). When ISO-NE has surplus capacity, load shedding risk in all seasons is lower than at criteria conditions.

marginal reliability value in summer, when the gas system is not constrained. The 2022 CELT 90/10 summer load forecast for 2025 is 5.2 GW higher than the winter load forecast. Hence, if only a small amount of capacity faces winter fuel risks, load shedding risk is likely to be concentrated almost exclusively in summer months. This is because the capacity needed to meet summer peak load is more than enough to reliably meet winter peak load. In this case, resources facing winter fuel restrictions still have high marginal capacity value because they are reliable in the period when capacity is most valuable (summer). By contrast, if a large portion of the system's capacity faces winter fuel limitations, winter months will exhibit a greater reliability risk despite having lower peak load and the marginal value of these resources will be low.

Efficient Accreditation of Pipeline Gas-Dependent Generation

Figure 10 illustrates why a marginal capacity accreditation approach will provide efficient incentives to address winter reliability issues and an average accreditation approach will not. When load shedding risk is concentrated in winter, pipeline gas resources without LNG will receive very low capacity payments under an MRI-based approach because they do not improve winter reliability. The owners of these resources will then have strong incentives to procure firm LNG deliveries or invest in dual fuel capability because these actions would increase their capacity payment by up to 100 percent of the capacity price. We recognize that some of these responses may be limited by states' willingness to permit dual fuel infrastructure or by the 3-year ahead timeframe of the FCM. The latter issue can be addressed by transitioning to a prompt capacity market, which we discuss in the next subsection. The portion of resources that cannot take these actions will face incentives to retire and be replaced by more reliable capacity.

Under an average accreditation approach, pipeline gas generators that provide no marginal value would still receive relatively high capacity payments. In Figure 10, 8 GW of pipeline gas-dependent capacity without LNG would have an average ELCC of 69 percent despite having *no* marginal value. This is because the average value includes the amount of pipeline gas capacity that is valuable for meeting summer load before winter reliability risk increases. Such an approach would significantly overpay these resources since the average value of all 8 GW is immaterial to a given resource's value when the system is over-saturated with pipeline gas generators. As a result, average accreditation would not provide efficient incentives for resources without firm fuel to take actions to improve their winter reliability or retire.

Differences Between Summer and Winter Capacity Market Parameters

Our analysis of pipeline gas generation highlights the need to consider how the value of capacity differs between summer and winter seasons. Historically, most resources could provide similar amounts of capacity in summer and winter, so resource adequacy planning centered on procuring sufficient capacity to meet peak summer load. However, there are now large amounts of capacity that have higher availability in summer than winter, including:

- 8 GW of gas-only generation cleared in FCA16, a large portion of which may be unavailable on peak winter days if not backed by LNG;
- Gas-fired generators that have oil as a backup fuel are often unable to use duct burners and other output ranges when running on oil. As a result, approximately 800 MW of qualified capacity may be unavailable when these resources switch to oil in cold weather;
- 1.5 GW (nameplate) of solar PV cleared in FCA16, and solar is a fast-growing resource in New England. Solar PV resources listed in the 2022 CELT report have an average summer SCC of 41 percent and an average winter SCC of less than 1 percent.

The FCA is designed to procure the same amount of qualified capacity in all months of the year. ISO-NE conducts a single FCA each year covering a capacity commitment period (CCP) from June through May. Most resources with different levels of summer and winter QC may only offer the minimum QC that they can provide for the entire CCP. Alternatively, pairs of resources may form 'composite offers' that have the same aggregate summer and winter QC. Resources that receive a CSO through the FCA earn the same capacity price in each month of the CCP.

The FCA is not currently designed to recognize differences in seasonal reliability needs and compensate suppliers accordingly. As weather-driven renewables enter the market and ISO-NE implements improved capacity accreditation methods, a growing portion of capacity is likely to have unequal seasonal capacity values. An efficient market would compensate capacity in each season based on its marginal value, which is determined by the level of surplus reliable capacity relative to peak demand in that season. The current practice of procuring the same amount of capacity in each season and setting a uniform price regardless of seasonal surplus levels may have the following consequences:

- The FCA may be unable to procure the optimal amount of capacity in each season. The optimal amount of procurement in summer and winter may vary because demand is lower in winter, but resource availability is also lower. Because summer and winter cleared capacity must be equal, the FCA may be unable to procure surplus summer capacity that could contribute to improved reliability and lower prices.
- The FCA may fail to compensate resources based on their marginal reliability value. For example, suppose a resource with high summer QC and a resource with high winter QC form a composite offer and obtain a CSO. Both resources receive the same price per kW-month, even if one member of the pair provides the vast majority of the reliability benefits. This reduces incentives to invest in resources that have higher marginal value when capacity is most needed.
- Conducting the FCA on an annual basis may limit the flexibility of resources to take actions targeting seasonal reliability needs, such as securing LNG supply ahead of a winter season. This concern is related to issues with the mandatory forward capacity market discussed in the next section.

C. Assessment of the Mandatory Forward Capacity Market

ISO-NE procures capacity to satisfy resource adequacy requirements primarily through the Forward Capacity Auction (FCA). The FCA is conducted over three years before the associated Capacity Commitment Period (CCP). The processes to develop auction parameters and qualify participating resources take place over the course of approximately a year before each FCA.

Participation by load-serving entities in the FCA is mandatory. The FCA is the main avenue for new resources to obtain a Capacity Supply Obligation (CSO) and receive capacity revenues. The ISO also conducts annual reconfiguration auctions (ARAs) that allow resources to gain or shed a CSO closer to the commitment period. However, the role of the ARAs is limited due to the mandatory nature of the FCA.

In this subsection, we evaluate the efficacy of the mandatory three-year forward FCA, contrasting the forward framework with a prompt capacity market that conducts auctions shortly before the commitment period (e.g., weeks or months). Both forward and prompt frameworks require load-serving entities to satisfy their procurement obligations; the difference is in the timing of procurement relative to the CCP.

Role of FCA in Coordinating Investment

The main purported benefit of a mandatory forward market is that it provides price certainty for investors seeking to finance new projects or invest in existing capacity. This would reduce investors' market risk and make them more likely to bring forward new projects. The FCA is also purported to facilitate planning by ensuring that there is sufficient available supply in advance of when it is needed. We discuss each of these assumed benefits below.

Price Certainty. The FCA no longer provides significant price certainty for major projects. In late 2020, FERC ordered ISO-NE to end its practice allowing a new resource to 'lock in' the price it received in its first FCA for up to seven years.[41] Resources that receive a CSO now receive the prevailing capacity price for only a single CCP. One year of guaranteed capacity revenue is unlikely to cover a meaningful portion of a resource's investment costs, which typically have project amortization periods of 20 years or more. Even with prices clearing at the Net Cost of New Entry (Net CONE) of $7.4/kW-month, a single-year CSO would cover less than 11 percent of the capital cost of a new gas peaking unit or 7.6 percent of a new four-hour battery. Hence, developers must already rely on expected future revenues or forward contracts.

Evidence from other regions does not support the notion that a mandatory forward capacity market is necessary to encourage merchant investment when it is needed. For example, 2.3 GW

41 This practice, while providing significant revenue certainty for new resources, was discriminatory in favor of new projects and in some cases inefficiently allowed resources to lock in capacity payments that were much higher than the value of that capacity in subsequent years. See FERC Docket EL20-54.

of merchant generation has been financed and built in the past decade in New York ISO, which operates a prompt capacity market immediately prior the capability period. Developers of these projects have mitigated their revenue risks through bilateral hedges such as revenues puts.[42] Spot markets provide a basis for investors to enter into forward contracts with loads or financial intermediaries, even when loads are not mandated to buy capacity on a forward basis. Since a prompt capacity market would facilitate such contracts, a forward capacity market is neither needed nor effective in providing the price certainty developers claim they need.

New Entry in the FCA. The FCA provides a small amount of revenue certainty if the project enters service on time. However, the FCA had a dubious track record of coordinating timely entry of new resources even before the multi-year lock-in was eliminated. Figure 11 shows new generation projects that received CSOs of at least 50 MW for the CCPs beginning June 2016 through June 2022.

Figure 11: New Generation Projects with Initial CSO above 50 MW

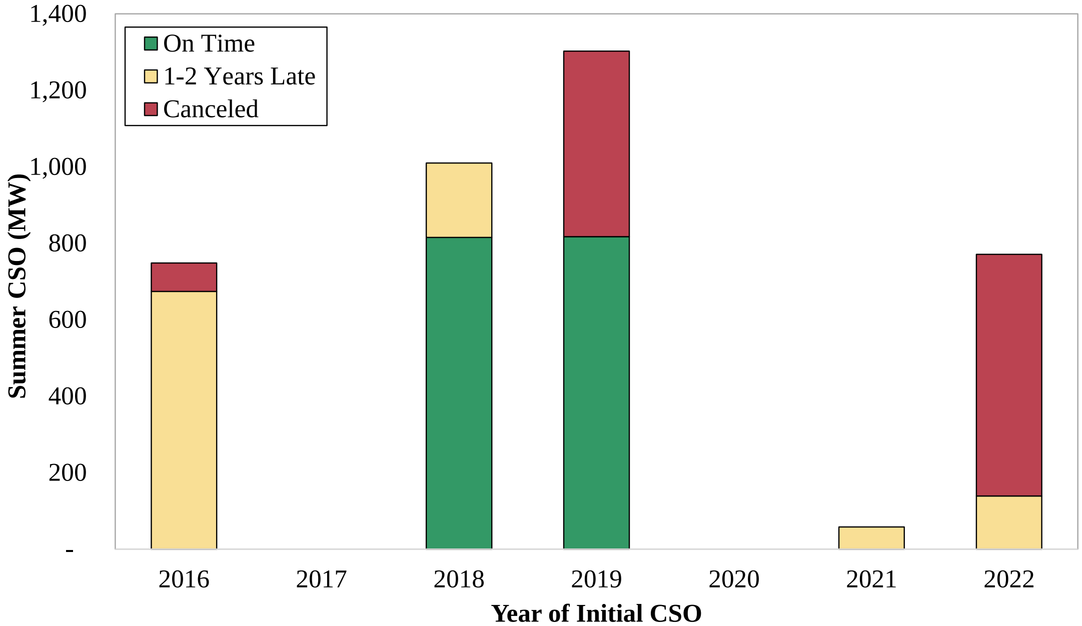


Figure 11 shows that out of 3.9 GW of such projects, 1.6 GW (42 percent) entered service on time to satisfy their initial CSO, 1.1 GW (27 percent) entered (or are expected to enter) later than the summer of their initial CSO, and 1.2 GW (31 percent) never delivered their CSO because the project was canceled or failed to meet development milestones.[43] The projects that entered on time all opted to receive multi-year price guarantees, an option which is no longer available.

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42 For example, owners of the 1.1 GW Cricket Valley Energy Center and 680 MW CPV Valley Energy Center have publicly indicated that they obtained voluntary revenue hedging agreements for the first five years of plant operations.

43 Projects with initial CSOs in 2022 include Killingly Energy Center, which had its CSO terminated for failing to meet milestones, as well as the Vineyard Wind and Three Corners Solar projects, which we

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The three-year forward term of the FCA is not aligned with development timeframes for a growing share of projects in ISO-NE. Three years was originally thought to correspond to the construction period for a new fossil peaking plant. However, a large share of new capacity now comes from projects with different characteristics:

- Of the 1.6 GW of new generation capacity that received CSOs in the past three FCAs, 1.1 GW (72 percent) was from solar and battery projects, both of which can often be constructed in significantly less than three years.
- Over 700 MW of new demand resources cleared in the last three FCAs, including energy efficiency, active demand response and load reductions provided by behind-the-meter solar and storage.[44] These projects are typically aggregations of devices installed by individual end-users and do not require lengthy construction timelines.

The FCA may actually inhibit resources with fast development timeframes from receiving capacity payments as soon as they are able to support reliability. For example, 848 MW (nameplate) solar and storage resources that entered service between January 2016 and April 2022 first participated in an FCA whose CCP was much later than the project's actual in-service date. While these resources can in principle secure a CSO through an ARA or bilateral trade, volumes and prices in these auctions are typically much lower than in the FCA.

Disadvantages of Mandatory Forward Capacity Market

The previous subsection demonstrates that the three-year forward FCA is less important for coordinating new investment than has often been assumed. However, the FCA has significant disadvantages compared to a prompt capacity market.

Higher Financial Risks. Developers that earn a CSO through the FCA but are not in service by the commitment period face financial penalties. Projects that are up to two years late or cannot fully satisfy their CSO must buy capacity to make up their obligation. Projects that are more delayed may have their CSO canceled, face significant penalties by forfeiting financial assurance, and must restart the qualification process in order to sell capacity in a subsequent auction. This creates the following development risks for resources that sell capacity:

- Large projects such as offshore wind face uncertain development timeframes and may fail to be in service by the date associated with their CSO. For example, the Vineyard Wind project off the coast of Massachusetts received a CSO beginning in June 2022 but will not be in service until at least 2023.[45]

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assume to be at least one year late due to publicly available information that they are not likely to be in service on time to meet their initial CSO in summer 2022.

44 We have recommended that energy efficiency be removed from the supply side of the capacity market and treated as a load reduction instead. See our 2020 Assessment of the ISO-NE Markets. If treated as a load reduction, EE resources would still produce more timely cost savings under a prompt auction framework.

45 As of May 2022, Vineyard Wind's website states that it will first deliver power in 2023 and ISO-NE's interconnection queue lists its commercial operation date as October 2023.

- Large conventional projects may similarly encounter delays due to both regulatory and construction risk.[46] In a prompt market, developers can manage these risks by delaying or discontinuing the project, but these actions are more costly in forward market.
- Small-scale clean energy projects (including most solar and storage projects) often do not have EPC contracts and other project details finalized three to four years in advance. As a result, these projects may have to submit FCA offers before they have certainty regarding the costs of major components such as batteries and solar panels and when development of the project may be uncertain even if a CSO is awarded. Alternatively, some projects may choose not to sell in the FCA until these details are more certain, causing them to forego capacity revenues in the first year or two of operation.
- Demand resources backed by aggregations of small consumers (including aggregations of behind-the-meter solar and storage) typically do not sign contracts with customers over three years in advance. In order to participate in the FCA, these providers must estimate potential future sales and face the risk of not providing enough demand reduction to satisfy their CSO. This is one reason why EE providers routinely offer less capacity in the FCA than they actually install.[47]

A prompt capacity market avoids these risks because project owners simply offer their capacity in prompt auctions once the project is in service or nearly complete. This aligns the timing of capacity payments with each resource's actual in-service date.

Poor Facilitation of Retirement Decisions. The forward market also creates significant financial risks for existing older generators. This is because retirement of older units is often prompted by unforeseen equipment failure that is not economic to repair (as opposed to planned retirement mediated through the FCA). Such units must accept a CSO that ends more than four years after the FCA. This raises two significant concerns:

- The FCM structure can cause resource owners to be unable to satisfy a CSO if it suffers equipment failure that is not economic to repair. This possibility creates a substantial risk for older existing generators that are marginally economic.
- This risk can cause older resources to retire prematurely. If the capability of an old unit 3 to 4 years in the future is sufficiently uncertain, it may be rational for the supplier to simply decide not to accept a CSO and retire the unit.

FCM increases the Misalignment Between Planning Models and the Capacity Market. It will become increasingly challenging for the FCA to value capacity accurately as the resource mix becomes more diverse. This is because the FCA must rely on planning models that assume a resource mix that is different from what is actually procured in the auction. With an evolving

46 For example, the Footprint Combined Cycle project entered service two summers later than its original CSO after significant delays and ultimate termination of its first EPC contract. However, this led to a $236 million arbitration judgment against the developer for wrongful contract termination in March 2022.

47 See ISO-NE filing letter in FERC Docket ER20-2869

resource mix, projects face financial risks as their capacity value is updated between the FCA and capability period. This subsection further explains this issue.

A key difference between forward and prompt capacity markets is the degree of uncertainty regarding the supply mix prior to the auction. Before a prompt auction, there is a high degree of certainty about the mix of resources that will clear because participants are already in service or near completion. In a forward auction, a range of potential new resources and retirement offers may be selected, and resources that obtain CSOs might ultimately fail to enter by the CCP. The longer the forward term of the auction, the greater the uncertainty regarding the resource mix.

This uncertainty is problematic because it causes assumptions underpinning key auction parameters to differ from actual market outcomes. ISO-NE uses its resource adequacy model to calculate the ICR before the FCA is conducted, but the results of the resource adequacy model depend on the assumed resource mix. For example, assuming a large amount of wind will produce a different ICR and marginal capacity credit values than assuming a small amount.

Large amounts of new capacity from intermittent renewables and storage will enter the market in the coming years. Hence, in its resource adequacy model, the ISO will either underestimate the penetration of these technologies or apply speculative assumptions about which technologies will clear before the auction.[48] This will have the following effects:

- The ICR used in the FCA will not correspond to the level of capacity that satisfies the 1-in-10 reliability target because it will be based on an inaccurate resource mix, and
- Capacity credit values used in the FCA will be over- or under-estimated for resources whose marginal value depends on their penetration.

These issues will increase financial risks for some resource types selling capacity in the FCA. Capacity credit values and the ICR will change between the FCA and the capability period as the resource adequacy modeling assumptions become more accurate. For example, suppose a large amount of new short-duration storage clears in the FCA. Before the auction, the capacity credit of the storage will have been over-estimated and the ICR will have been under-estimated because these resources will have been excluded from the resource adequacy model. When the resource mix is updated for subsequent ARAs with the FCA results, the capacity value of storage units will be reduced, requiring them to buy out of part of their CSO at potentially high cost.[49]

48 Currently, only existing resources and projects that have already cleared in a prior auction are included in the resource adequacy model for the FCA. Changes to inclusion rules in the resource adequacy model are not likely to resolve this issue as long as there is a range of potential outcomes for the resource mix that clears the FCA. In the example provided for FCA15, inclusion of all qualified storage projects in the model would have over-estimated the penetration of storage by 1.1 GW instead of underestimating it.

49 Under an alternative design, resources that clear the FCA might be permitted to lock in the capacity credit they were originally assigned. However, this would simply shift these financial risks from developers to consumers, leading to inefficient incentives and increased consumer costs as additional capacity must be procured to make up for resources that were overvalued in the FCA.

These problems are significantly reduced or eliminated in a prompt capacity market because there is much less uncertainty in the supply mix that will clear. A prompt capacity auction would tend to produce values for capacity credit and the ICR that are consistent with the mix of technologies in the corresponding capability period.

Misalignment with Fuel Contracting Opportunities. The capacity credit of pipeline gas generators will depend on whether they contract for firm transportation and/or LNG deliveries if proposed improvements to capacity accreditation rules are adopted. However, the capacity credit of resources participating in the FCA will be determined nearly four years in advance of the winter portion of the associated CCP.[50] This would require resources to arrange for firm fuel supply far in advance of the delivery date to improve their capacity credit in the FCA, which is likely undesirable for many resource owners. Alternatively, some pipeline gas resources may accept low credit in the FCA even if fuel contracts are economically available closer to the CCP, causing the FCA to over-procure capacity for winter reliability needs.

In a prompt market, the auction is conducted closer to the timeframe when generators are likely to sign contracts for firm fuel supplies for the coming winter season. This is particularly true if the prompt market is conducted on a seasonal basis (e.g., summer and winter capacity auctions). This would facilitate generators choosing the optimal amount of new fuel contracts based on expectations of revenues in the prompt market.[51]

D. Rising Financial Risk for New Capacity Investment

In early 2022, ISO-NE filed tariff changes with FERC to eliminate its Minimum Offer Price Rule (MOPR) beginning in FCA19 auction to be held in 2025. Eliminating MOPR will lower barriers to participation in capacity markets by resources sponsored by New England states. However, an important consequence of eliminating the MOPR is an increase in financial risk for merchant resource owners. This is because resources that receive state contracts and other out-of-market revenues may enter regardless of market conditions, increasing the likelihood of extended capacity surpluses and correspondingly low capacity prices. The timing and quantities of future state-sponsored projects are uncertain, so projects that rely on capacity revenues (including clean energy technologies) face greater market risk in the absence of a MOPR than they would if new entry was governed only by wholesale market conditions.

50 The FCA is usually conducted in February and the associated CCP begins in June three years later. Hence, the portion of a resource's CSO that begins in December is approximately 46 months after the FCA.

51 For example, if reliable winter supply is expected to far exceed peak load, prompt winter capacity prices would be low and all pipeline gas generators need not incur the cost of obtaining firm fuel. On the other hand, if winter reliability risk is expected to be high, winter capacity prices would be high and generators would face incentives to firm up as much supply as possible to receive higher capacity payments.

The capacity market plays a critical role in incentivizing entry of new resources to support reliability. The capacity market demand curve is designed so that the price will equal the net cost of new entry (CONE) of a new peaking unit when new capacity is needed to satisfy the installed capacity requirement (ICR).[52] The ISO periodically estimates the CONE based on a review of the costs of a new peaking plant, including the cost of capital that would be required by investors relying on risky merchant revenues to recover the costs of the plant.

In order to meet the capacity market's objectives, factors that increase the cost of capital for a merchant peaking plant should be considered in the CONE study. Otherwise, the demand curve will not provide enough revenue to encourage new entry when it is needed for reliability. This could lead to a chronic need to use out-of-market reliability agreements to prevent retirement of existing units instead of relying on efficient merchant entry.

Recent CONE studies have estimated the cost of capital of a new entrant based on a review of historical returns required by investors in power generation assets operating in regions with competitive wholesale markets. Each of these markets is either in a state jurisdiction with limited policy intervention or has limited the price effects of subsidized entry with a MOPR. Hence, the available historic data does not reflect the returns an investor would expect in a competitive power market without a MOPR and high levels of policy-driven investment. Hence, it is important to account for the effects of eliminating the MOPR provisions on the WACC.

We performed a study in 2021 of the potential impact of eliminating the MOPR on the cost of capital for merchant resources.[53] We used a Monte Carlo model to simulate revenues of a hypothetical peaking unit with and without elimination of the MOPR under a range of scenarios of policy-driven investment. We relied on studies conducted by state governments and other public information to develop a range of policy-driven entry levels for clean energy technologies. Our study found that the revenues of the peaking unit would be more volatile without the price-moderating effects of the MOPR.

This study estimated that eliminating the MOPR would cause the after-tax weighted cost of capital for the peaking resource to increase by 225 basis points, which corresponds to a 16 percent increase in the Net CONE. This study demonstrates that the ISO should explicitly consider the effects of state policies on merchant investment risk and the net CONE used to set the capacity market demand curve.

52 The new unit for which the CONE is estimated has generally been a natural gas-fired combustion turbine. This assumed technology may warrant re-evaluation in the future if fuel or regulatory limitations make such resources difficult to develop.

53 See "EMM Evaluation of Changes in MOPR Rules on Financial Risk in New England", available here.

E. Conclusions and Recommendations

Rapid change in New England's power sector will require capacity market design enhancements in order to efficiently facilitate investment and retirement. This section discusses the following concerns with ISO-NE's current forward capacity market:

- Current resource adequacy modeling and capacity accreditation techniques will not accurately assess the system's reliability or send efficient signals for investment;
- The lack of seasonal price signals and requirements will cause the capacity market to fail to procure the optimal amount of capacity or incent gas generators to obtain firm fuel;
- The mandatory three-year forward nature of the FCA is no longer useful for coordinating new investment and will inhibit efforts to implement efficient capacity accreditation; and
- The FCA timeframe undermines generators' ability to make efficient retirement decisions for old resources whose availability is uncertain three to four years in the future.
- The capacity market demand curves may fail to attract new capacity when needed for reliability if not adjusted to consider the effects of MOPR elimination.

To address these concerns, we recommend the following key changes to the FCM:

Recommendation #2020-2: We recommend that ISO-NE improve its capacity accreditation rules to accredit resources based their marginal reliability value and modify the resource adequacy model to enable accurate estimation of the marginal reliability value of different types of resources. Improving accreditation in this manner will:

- Provide efficient incentives to investors by aligning capacity payments with the impacts of resources on system reliability.
- Account for the diminishing value of resources whose availability is correlated and discourage over-dependence on a single resource type.
- Facilitate a diverse resource mix by rewarding resources that provide output that is uncorrelated with other resources or that complement other resources in the system.

Under the recommended framework, each resource's compensation reflects: (a) the expected ability of the resource to provide output in critical hours based on the type and characteristics of the resource, and (b) the historic performance of the individual resource relative to other resources of the same type. The expected capacity value of a resource should be estimated by measuring how an incremental addition of that resource impacts a reliability metric (such as LOLE or MWhs of unserved load) in ISO-NE's resource adequacy model.[54]

54 This is the Marginal Reliability Improvement (MRI) method. Marginal capacity value can also be calculated using the Marginal ELCC method. As explained in the Appendix Section VII, Marginal ELCC and MRI are likely to produce similar results. We expect that MRI is advantageous because it is less computationally intensive and is already used in ISO-NE's capacity demand curve.

ISO-NE will need to enhance its resource adequacy model to accurately assess the value of each resource type and the ICR needed to satisfy resource adequacy criteria. In particular, ISO-NE's GE-MARS model should be modified to consider the characteristics of intermittent resources, energy storage, generators with correlated fuel limitations (such as pipeline gas), and units with long startup lead times.[55]

Recommendation #2021-1: We recommend eliminating the mandatory forward capacity auction and replacing it with a mandatory prompt seasonal capacity auction. As is the case today, the ISO would determine an Installed Capacity Requirement and procure capacity using its MRI-based demand curve. Load-serving entities would still be required to purchase capacity corresponding to their load-ratio share of the ICR. However, LSEs would not be required to purchase capacity three years in advance and would instead be responsible for purchasing it in the prompt auction prior to each capability period. Hence, the auction would retain its structure and mechanics, but it would take place closer in time to the corresponding capability period.

To fully address this recommendation, ISO New England should:

- Conduct the mandatory capacity auction weeks or months prior to the associated capability period;[56]
- Conduct at least two prompt auctions annually (for the summer and winter seasons) using capacity market demand curves that reflect the marginal value of capacity in each season;
- Eliminate the annual reconfiguration auctions (ARAs), which will not be necessary in the absence of mandatory three-year forward auction; and
- Simplify the capacity qualification process to account for a shorter lag between qualification and the CCP.

If the ISO transitions to a prompt market framework, we recognize that it will require significant conforming changes to the interconnection and reliability planning processes. Significant effort will be necessary to develop new processes for batching and sequencing interconnection studies, assignment of cost allocation and financial assurance for transmission upgrades, and determination of capacity sales rights.

However, switching from a forward to a prompt FCA would generate the following substantial benefits:

- Reduce development risk associated with FCA participation by awarding a CSO only when a resource is in service or nearly complete;
- Facilitate more efficient investment in resources with fast development timelines by allowing them to receive capacity payments more quickly after entry;

55 See Section VI.D of our 2020 Assessment of the New England Electricity Markets.

56 This recommendation would not preclude the ISO from running a non-mandatory forward market which would facilitate voluntary hedging by buyers and sellers of capacity.

- Align assumptions underlying GE-MARS with the actual resource mix so that the ICR and capacity credit ratings are determined accurately;
- Efficiently compensate resources that provide different summer and winter capacity;
- Facilitate efficient retirement decisions by old existing generating resources by eliminating the risk of accepting CSOs three to four years in advance.
- Permit a greater range of capacity cost hedging options by load-serving entities instead of requiring all obligations to be satisfied three years in advance; and
- Simplify administration of the capacity market by eliminating the need to rely on multi-year forecasts of auction parameters and closely monitor the progress of new projects.

Recommendation #2021-2: We recommend that ISO-NE explicitly consider the impact of eliminating the Minimum Offer Price Rule (MOPR) on merchant generators' cost of capital when establishing the Net CONE value used in its capacity market demand curve. In the short term, it may be necessary to direct ISO-NE's demand curve consultant to estimate an appropriate risk adjustment based on expected changes in market volatility due to elimination of the MOPR. In the long term, the widespread removal of MOPR provisions in U.S. capacity markets will be reflected in financial market data and such an adjustment may not be necessary.

Recommendation #2015-7: We recommend replacing the descending clock auction with a sealed-bid auction. We have detailed in previous reports that ISO-NE's DCA process inadvertently provides information that may help suppliers with market power influence auction prices.[57] A sealed bid auction would eliminate such information and improve the incentives for suppliers to submit competitive offers. In addition, the DCA format adds unnecessary complications that may interfere with other enhancements recommended in this section, including accurate determinations of resources' marginal reliability value. Hence, we recommend the ISO transition to a sealed-bid auction.

57 See our 2014, 2015 and 2017 Assessment of the ISO New England Electricity Markets.

V. Market Operations During January 2022

The markets in New England and eastern New York have become increasingly vulnerable to natural gas limitations during cold weather conditions over the past decade with the retirement of older oil-fired, dual-fuel, and nuclear generation. Additional generators have signaled their intent to retire, although the retirement of the Mystic combined cycle generators (which are supplied with LNG) has been deferred until June 2024. Given the current capacity surplus measured relative to the summer peak load conditions, additional retirements of oil-fired and dual-fuel generation appear likely.

In Section IV, we recommend that ISO-NE enhance its resource adequacy model and capacity market to provide efficient market incentives for addressing fuel security needs. However, even with these enhancements, the ISO will continue to rely on its energy and ancillary services markets to coordinate the efficient commitment and dispatch of oil-fired and gas-fired generation. Day-ahead and real-time prices must accurately reflect the marginal cost of the supply needed to satisfy system needs in order to provide efficient incentives to procure fuel and perform reliably. Therefore, it is important to assess whether the day-ahead and real-time markets function efficiently during winter weather conditions to ensure that suppliers have appropriate incentives to be available. Conditions in January 2022 provided an opportunity to evaluate this aspect of the markets' performance so in this section we review:

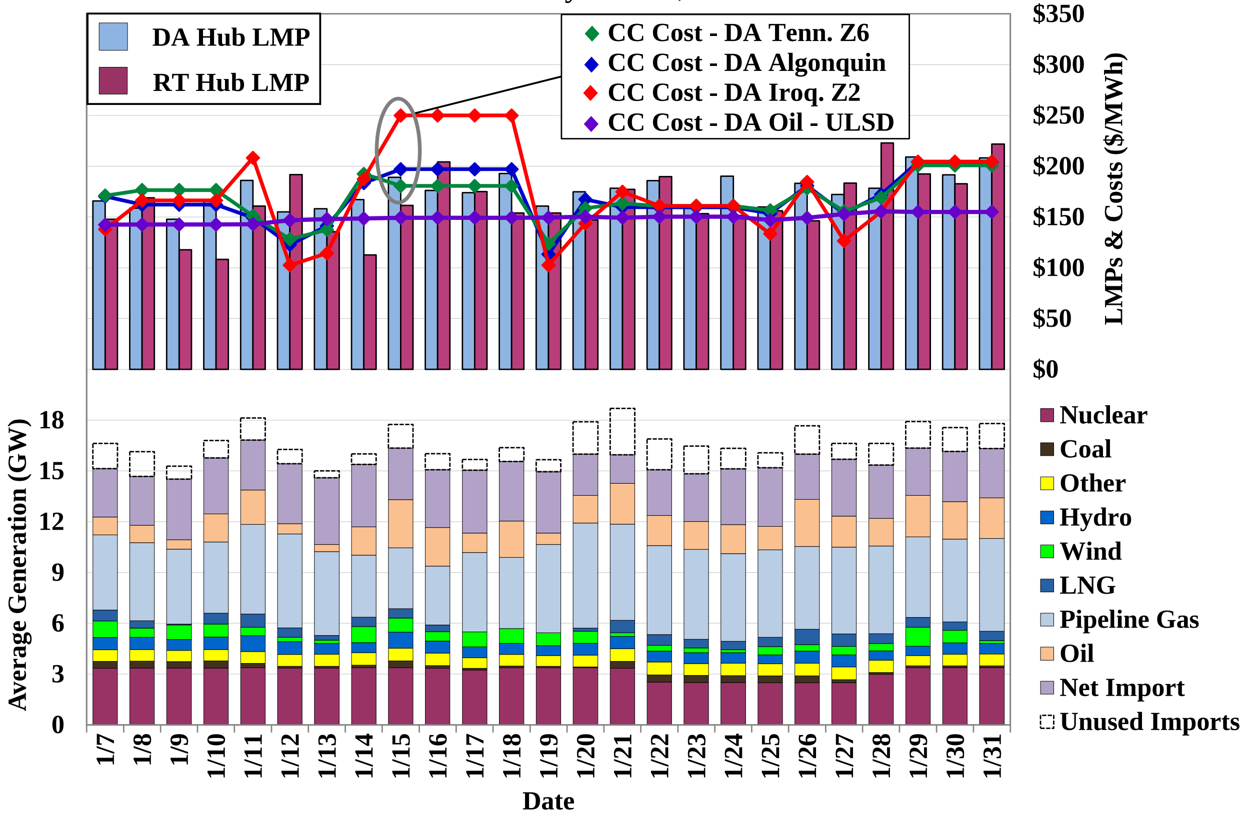
- Fuel and electricity prices to determine whether they were consistent with the commitment and scheduling of individual generators;
- Utilization of oil-fired and dual-fuel resources to identify factors that may have limited their availability;
- Production from gas-fired generation to determine how well day-ahead gas price indices reflected the cost of fuel to these units; and

These analyses provide insight about how well the day-ahead and real-time markets coordinate the utilization of resources with limited fuel inventories and reward suppliers that ensure fuel is available to run their plants. Our conclusions are provided at the end of the section.

A. Evaluation of the Supply Mix and the Prices for Fuel and Electricity

This subsection shows sources of supply that New England used on days with tight gas market conditions in January 2022. Our analysis evaluates the consistency of prices and energy output with the production costs of different types of units. The bottom panel in Figure 12 shows the amount of generation supplied by each fuel type during the period by date, the net imports to New England and the amount of unused import capability. The top panel shows the average daily day-ahead and real-time LMPs at the New England Hub compared to the variable production cost of hypothetical combined cycle resources with heat rates of 7.0 MMbtu per MWh burning natural gas procured day ahead from Algonquin, Iroquois Z2, and Tennessee Z6, and from Ultra-Low Sulfur Diesel ("ULSD"). The estimates include $3 per MWh of variable O&M, RGGI compliance costs, and $3 per MMbtu for ULSD delivery costs.

Figure 12: Generation by Fuel Type and Imports to New England
January 7 to 31, 2022



This evaluation provides several useful insights about market operations on days with very tight gas market conditions.

- Nuclear, coal, other (wood/refuse), hydro, and wind ran at high output levels and satisfied 4.5 to 6.3 GW (30 to 41 percent) of load on these days. The total from these categories has fallen from previous cold winters primarily because of retirements. For example, they accounted for an average of 7.1 GW in the 2017/18 cold spell.
- LNG-fired generation fell significantly from the 2017/18 winter cold spell, providing an average of 470 MW of supply on these days (down 45 percent). Tight conditions in global natural gas markets led to steep LNG price increases and reduced shipments to New England generators.[58]
- Oil-fired generation use was low (averaging 10 percent of load), especially given its apparent cost advantage relative to natural gas price indices on most days. In total, oil generation averaged 1.4 GW and rose as high as 3 GW on the highest load days when gas system conditions led to higher positive spreads between gas prices and oil prices.
- Net imports were substantial, accounting for an average of 3.2 GW on these days.

58 See "Winter Operations Recap Winter 2021-2022" by Mike Knowland at https://www.northeastgas.org.

- Pipeline-gas-fired generation was relatively consistent, providing an average of 4.8 GW of output on these days. However, this category fell to as low as 3.5 GW on the highest load days when the spread between gas and oil prices was highest.

These results raise two issues that are addressed later in this section. First, oil-fired output satisfied up to 17 percent of load on these days, which is substantial even though the winter was unusually cold. Nonetheless, some apparently economic oil-capable generation was not utilized to burn oil. Subsection B identifies factors that reduced utilization of economic oil generation. We evaluate these factors and assess whether they arise from a deficiency in the market or from normal issues that should be expected to occur in a well-functioning market. Second, pipeline-gas-fired generation was produced on many days when pipeline gas appeared to be uneconomic based on day-ahead gas index prices, which is evaluated in Subsection C. In particular, we discuss factors that led pipeline gas to be more or less expensive than would appear based on these index prices.

B. Utilization of Oil-Fired and Dual-Fuel Capacity

In a competitive market, dual-fueled generators are expected to use the most economic fuel to produce power. Generators offer into the day-ahead and real-time markets on the lowest cost fuel, and the ISO selects the most economic offers across the system to satisfy demand and reserve requirements. Through this process, the ISO coordinates the utilization of different fuels efficiently while maintaining reliability. When individual generators offer to use the fuel type that is apparently more expensive, it can be an indication of an operating constraint or market factor that could become more significant under more severe conditions.

This subsection evaluates the use of oil-fired and dual-fuel capacity during this period, eliminating the few days when gas prices were lower than ULSD prices.[59] We estimate the amount of capacity that would have been economic based on the variable cost of generating from fuel oil, assuming no logistical, mechanical, or environmental limitations other than explicit air permit restrictions. Of the 13.7 GW of winter capability listed in the CELT report as dual-fueled or oil-fired, approximately 6 percent (or 15 percent of the combined cycle total) is unable to operate on oil because of equipment limitations and/or air permit restrictions. Most of this is duct-firing equipment that is not permitted and/or not configured to burn oil on combined cycle units that are able to burn oil in the main combustion turbines.

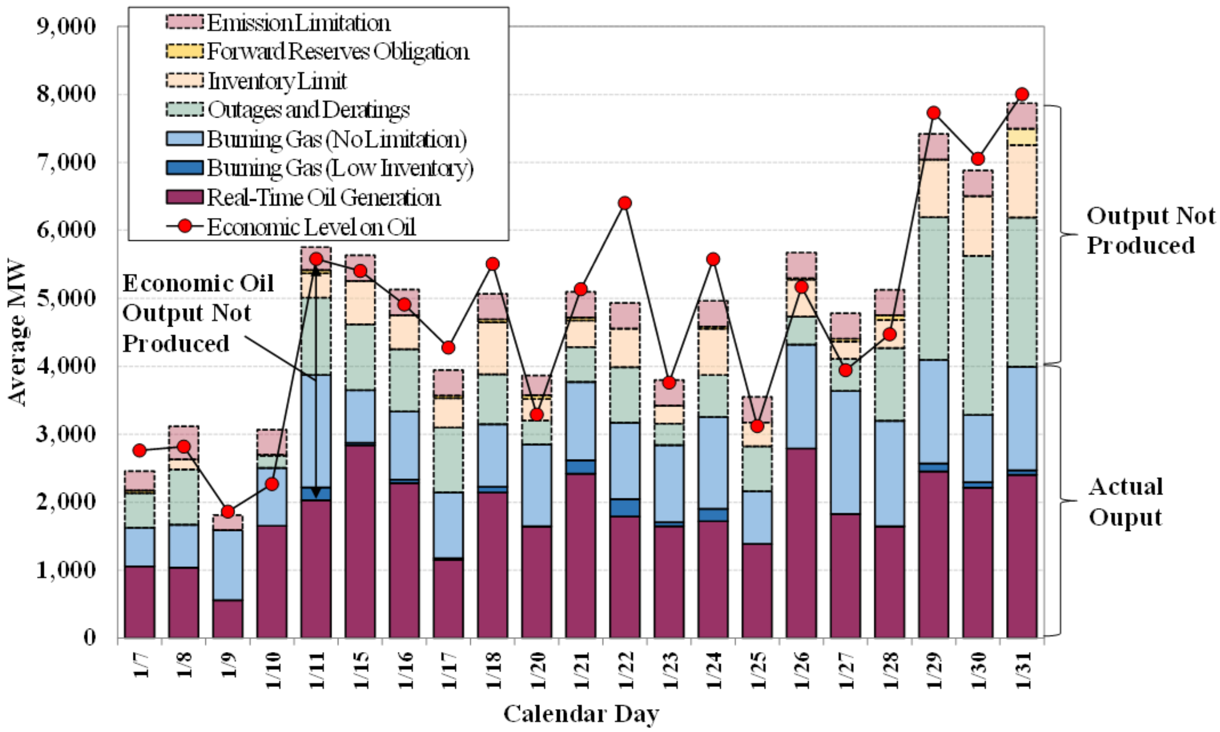
Figure 13 shows our estimates of the amount of oil-capable capacity that would have been economic to burn oil based on day-ahead and real-time clearing prices each day (the red circles).[60] The figure also shows the actual output produced from oil and natural gas in these

59 Gas prices for all three of the major indexes were lower than ULSD prices on each of Jan 12, 13, and 19. January 14 results were also excluded due to the mismatch in timing between electric and gas market days.

60 We assume economic commitment of fast-start generation is done in accordance with real-time prices while economic commitment of slow-start generation is done in accordance with day-ahead prices.

units along with the amount of economic oil output that was likely limited by four different factors.[61] This assessment provides key insight about how efficient markets should affect the availability of generation with firm fuel supply during periods of natural gas scarcity.

Figure 13: Utilization of Oil-Fired and Dual-Fuel Capacity
Selected Calendar Days in January 2022



Actual oil-fired output averaged 41 percent of the capacity that we estimate would have been economic to burn fuel oil on these days. Alternatively, 27 percent of the estimated economic oil-fired output was actually produced by burning natural gas for the following reasons:

- *Favorable Gas Costs*. Most of the output from gas (84 percent) came from either baseloaded cogeneration plants or plants that are situated favorably on the Tennessee and Algonquin pipelines in western Massachusetts or Connecticut. Generators upstream of key pipeline constraints often have better access to gas at potentially lower prices.
- *Operational Benefits*. The choice of fuel may affect the operational characteristics of the generator. For example, burning oil may restrict access to duct-firing ranges on a combined-cycle unit and lower its potential output.
- *Oil Inventory Management*. Generators with limited oil inventories may burn natural gas to conserve their oil, although this was not likely a significant factor during this period.
- *Total Emissions Limits*. Air permit restrictions may limit a generator's number of oil-fired hours per year, which was also not likely binding in January 2022.

61 Non-forced outages and deratings were not significant during this period. The ISO operators did not posture (i.e., hold a generator in reserve through an OOM action) any oil-fired units during the period.

The remaining 32 percent of estimated economic oil-fired output was not produced because of:

- *Forced outages and deratings*. Led an average of 860 MW to be unavailable over the period and over 2.3 GW from January 29 to 31.
- *Inventory-limited units*. Accounted for an estimated 450 MW of unutilized capacity.
- *Emission rate limitations*. Accounted for 360 MW from generators that had difficulty keeping their emissions within the tolerances required by their air permits.

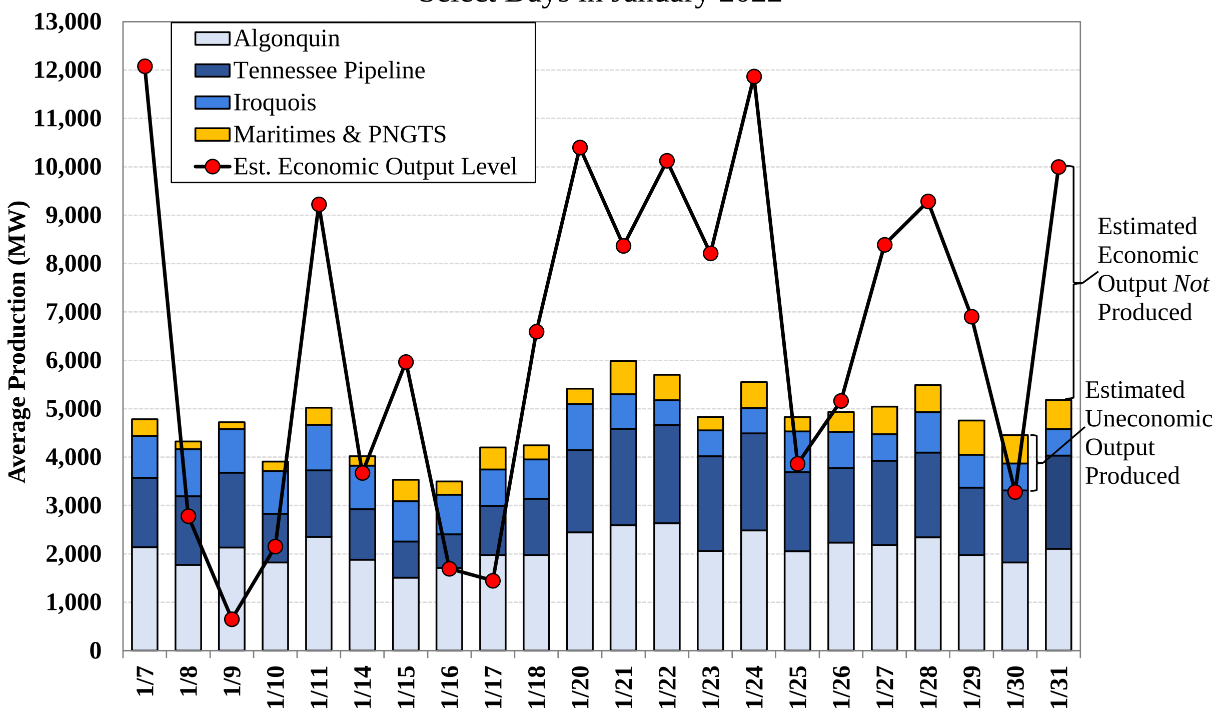
From January 29 to 31, the amount of generation economic to burn oil and oil-fired output both increased significantly partly because of forced outages and derates that raised prices and made higher cost oil-fired units economic. This highlights that when generators are incentivized through efficient day-ahead and real-time prices, they need not be compensated specifically for maintaining alternative fuel inventories. Efficient markets allow them to earn additional revenues by maintaining oil inventories and maximizing their resources' availability.

C. Analysis of Production by Pipeline-Gas-Fired Generation

This subsection evaluates the use of pipeline-gas-fired generation during this period to determine whether the marginal cost of these resources was efficiently reflected in clearing prices. This is important because it indicates whether the ISO-NE markets are providing economic signals to attract the necessary available supply under tight system conditions with limited gas availability. Figure 14 shows pipeline-gas-fired generation each day by pipeline relative to the generation we estimate would have been economic based on prevailing day-ahead gas prices for each pipeline.

Figure 14: Production by Pipeline-Gas-Fired Generation versus Wholesale Prices

Select Days in January 2022



Of the gas-fired generation that was economically scheduled during the period:

- 8 percent was supplied from the Maritimes and PNGTS pipeline;
- 16 percent was supplied from the Iroquois pipeline;
- 45 percent was supplied from the Algonquin pipeline; and
- 31 percent was supplied from the Tennessee pipeline.

The figure shows a relatively weak relationship between the production costs estimated from day-ahead gas price indices and other production input costs and wholesale prices. On twelve of the days shown, the estimated amount of economic gas-fired generation was at least 40 percent *higher* than actual gas-fired generation for several reasons:

- Some pipelines (especially Iroquois) require generators to burn a more consistent quantity across the day than would be optimal based on variations in power prices, reducing their profitability; and
- The day-ahead index prices generally reflect the prices of the gas transacted for these days, but additional quantities of gas may have been available only at a premium over the day-ahead prices published for the indices.

On five days, the estimated amount of economic gas-fired generation was *far lower* than the actual levels for related reasons. This reflects that gas sometimes becomes available at a lower price intraday than was available day-ahead. This can happen if actual consumption by core natural gas demand is lower than LDC's forecasts. For instance, generators on the Tennessee pipeline scheduled an average of nearly 50 percent more gas after the timely window on these days, while LDCs generally reduced their schedules after the timely window closed.

D. Conclusions

New England has become increasingly reliant on natural gas and vulnerable to disruptions in fuel supplies to the region. ISO-NE is considering capacity market enhancements to procure resources needed to maintain reliability during periods of extreme natural gas scarcity. Nonetheless, efficient day-ahead and real-time market performance will also help maintain reliability during winter conditions while minimizing costs to consumers. This section of the report evaluates market operations during cold weather conditions in January 2022. It demonstrates that:

- Generators do respond to the economic signals provided by the fuel markets and electricity markets. This underscores that producing efficient day-ahead and real-time energy and ancillary services prices is of paramount importance;
- This response by generators is not always easy to predict because they must consider an array of factors and limitations in making fuel procurement and burn decisions; and
- Real-time gas availability and cost can be highly uncertain, which will affect generators' fuel burn decisions, particularly under tight conditions.

VI. Appendix: Assumptions Used in Net Revenue Analysis

In this section, we list various assumptions underlying the net revenue estimates for various technologies discussed in Section I.E.

Net Revenues of Combustion Units

Our net revenue estimates of combustion units are based on the following assumptions:

- Natural gas costs are based on the Algonquin City Gates gas price index.
- In the day-ahead market, CTs are scheduled based on day-ahead prices, considering commitment costs, minimum run times, minimum generation levels, and other physical limitations.
- In the real-time market, CTs are committed in real-time based on hourly real-time prices and settle with the ISO on the deviation from their day-ahead schedule.
- CTs are assumed to sell forward reserves in a capability period when it will be more profitable than selling real-time reserves.[62]
- Fuel costs assume transportation and other charges of $0.27 per MMbtu for gas and $2 per MMbtu for oil on top of the day-ahead index price. Intraday gas purchases are assumed to be at a 20% premium due to gas market illiquidity and balancing charges, while intraday gas sales are assumed to be at a 20% discount for these reasons. Regional Greenhouse Gas Initiative (RGGI) compliance costs are included, if applicable.
- The heat rate and capacity for a unit on a given day are assumed to vary linearly between the summer values on August 1 and the winter values on February 1.
- The assumed operating parameters for combustion units are shown in Table 6:

62 We assume that CTs are capable of providing 70 percent of the UOL as the 30-minute reserve product and the remaining 30 percent as the 10-minute reserves.

Table 6: Unit Parameters for Net Revenue Estimates of Combustion Turbine Units

Characteristics	CT - 7HA
Summer Capacity (MW)	364
Winter Capacity (MW)	394
Heat Rate (Btu/kWh)	8,054
Min Run Time (hrs)	1
Variable O&M ($/MWh)	$1.8
Startup Cost ($)	$11,000
Startup Cost (MMBTU)	508.5

Net Revenues of Renewable Resources in New England

We estimated the net revenues of renewable units in ISO-NE using the following assumptions:

- Net E&AS revenues are calculated using real time energy prices.
- For cross-market comparison of land-based wind revenues, we utilized a generation profile that is based on inputs to NREL's ReEDS model.[63] For estimating net revenues, we used the generation profiles that were assumed in the 2019 Economic Study.
- The capacity revenues in each year are estimated using clearing prices from the corresponding FCAs. For our cross-market comparison of revenues, we assumed a capacity value of 16 percent for land-based wind.[64]
- We estimated the REC revenues for land-based wind using a 4-year average of the MA Class I REC Index for 2020 and 2021 vintages from S&P Global Market Intelligence.
- The net revenues of all renewable projects included Investment Tax Credit (ITC) or Production Tax Credit (PTC). The ITC reduces the federal income tax of the investors in the first year of the project's commercial operation. The PTC is a per-kWh tax credit for the electricity produced by a wind facility over a period of 10 years.
- The CONE for renewable units was calculated using the financing parameters and tax rates specified in the ISO-NE Net CONE and ORTP study.[65]
- For estimating the cost for entry, we utilized the cost trajectory from inputs to the NREL's ReEDS model.[66]

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63 For NREL data, see link.

64 See report on the ISO-NE Net CONE and ORTP Analysis. See Brattle study for Ney York for OSW capacity value assumptions.

65 See report on the ISO-NE Net CONE and ORTP Analysis, available at link

66 The capital costs for land-based wind units are based on the ISO-NE Net CONE and ORTP Analysis. We assumed 'Class 7-low' projections for adjusting the land-based wind costs. Fixed O&M costs for land-based wind units are based on the ISO-NE Net CONE and ORTP study. Region specific cost multipliers were applied to convert the US average costs reported by NREL.

Net Revenues of Land-Based Wind Resources in Other Markets

In this subsection we discuss assumptions underlying our net revenue estimates for land-based wind resources in three other markets. Net revenues and CONE estimates for the wind plant in NYISO are based on the information presented in the NYISO State of the Market report.[67] Net revenues of wind units in MISO and ERCOT are based on the following assumptions:

- Net E&AS revenues are calculated using real time energy prices in the South zone in ERCOT and in Minnesota for MISO.
- The energy produced by these units is calculated using location-specific hourly capacity factors. We considered capacity factor for recent wind installations in MISO and ERCOT, and the capacity factor information presented in 2021 NREL ATB for our assumption regarding the capacity factor for land-based wind in these regions.
- We estimated the value of RECs produced by the wind unit in ERCOT using a 4-year average of the Texas REC Index for 2020 and 2021 vintages from S&P Global Market Intelligence. For MISO, we utilized publicly available information on the REC prices in Minnesota.[68]
- Consistent with the assumption for other markets, we assumed full PTC revenues for the land-based wind plants in ERCOT and MISO regions.

Table 7: Land-based Wind Parameters for Net Revenue Estimates[69]

Parameter	ERCOT (South)	MISO
Investment Cost (2021$/kW)	$1,402	$1,430
Fixed O&M ($/kW-yr)	$44	$45
Federal Incentives	PTC	
Project Life	20 years	
Depreciation Schedule	5-years MACRS	
Average Annual Capacity Factor	35%	46%

67 See figure in the *2021 State of The Market Report for The New York ISO Markets*.

68 We used $1.10 per REC price based on the reported price range in the "Minnesota Renewable Energy Standard: UTILITY COMPLIANCE" document, available at: link.

69 The Fixed O&M and Investment costs are sourced from NREL ATB 2021, available at link. We assumed TRG-3 specific costs for the MISO wind unit, and TRG-7 costs for the ERCOT unit. Region specific cost multipliers were applied to derive the location specific costs from the US average costs reported by NREL.

VII. Appendix: MRI and ELCC Methodologies

In this report, we recommend accrediting capacity suppliers based on each resource's marginal reliability value. We recommend determining this value using the Marginal Reliability Improvement (MRI) method or marginal Effective Load Carrying Capacity (ELCC) method. These approaches differ from other methods that have been used for capacity accreditation, including 'average' ELCC and simple heuristic approaches. In this subsection, we explain the difference between MRI and ELCC approaches and discuss the advantages of marginal approaches in general and MRI in particular.

Approaches to Capacity Accreditation

In markets that procure a quantity of capacity based on a megawatt-requirement, capacity credit refers to the amount of megawatts a resource is allowed to offer and be compensated for in capacity market auctions. All frameworks to establish capacity credit use methods to either discount each resource's nameplate capacity or establish different prices for resources with different characteristics.

The concept of capacity credit is closely related to the system's reliability metric, which represents how reliable the system is. For example, ISO-NE targets a Loss of Load Expectation (LOLE) of 1 day in 10 years. This criterion is used to determine capacity market requirements (e.g., ICR), which are derived from simulations of LOLE that consider every resource's availability during hours when load shedding might occur. Ultimately, every resource's capacity credit should reflect its marginal impact on LOLE. Hence, a MW of accredited capacity from any resource type should correspond to a comparable impact on LOLE.

For some resource types, a random forced outage rate (EFORd) alone is not applicable or is not sufficient to reflect the resource's marginal impact on LOLE. Examples include intermittent renewables, energy-limited resources, long lead time or very large conventional generators, and generators that can experience a common loss of a limited fuel supply (such as a pipeline outage). One reason that EFORd alone does not accurately describe these resources' impact on reliability is that EFORd represents the probability of random uncorrelated forced outages. However, these resource types pose the risk of correlated outage or limited availability of a large amount of capacity under peak conditions.

There are multiple methods to assess the capacity credit of these resources. Capacity credit is often described relative to a hypothetical unit of 'perfect capacity' that is always available:

(a) Marginal Reliability Impact (MRI) – measures how an incremental amount of capacity of Resource X impacts LOLE or MWhs of expected unserved energy, relative to how the same amount of 'perfect capacity' impacts LOLE or MWhs of expected unserved energy.

(b) Effective Load Carrying Capacity (ELCC) – measures the MW quantity of 'perfect capacity' that would produce the same LOLE as a given quantity of Resource X.
   - ELCC approaches may be marginal or average, which is discussed further below.

(c) Heuristic approaches – estimate capacity credit based on rule-of-thumb approaches, such as a resource's average output in a predetermined set of hours.

Current ISO-NE Approach

ISO-NE's current approach to determining qualified capacity credit of intermittent and energy-limited resources relies on simple heuristics. The QC of intermittent generators, such as wind and solar, is determined based on their median output across certain hours each day in the winter and summer seasons.[70] Storage resources can offer QC up to 100 percent of their installed capacity if they can discharge for at least two hours. Our recommendation would eliminate these heuristic approaches and replace them with a common data-driven framework for all resource types.

ISO-NE currently does not adjust capacity credit for very large conventional generators or for units with common fuel security risks. The risk of a common outage affects their expected PFP risk, but there is no mechanism to preemptively reflect correlated risk of these units in their qualified capacity amount. Similarly, ISO-NE does not preemptively adjust capacity credit for units with long startup lead times, even though such units may perform poorly as a group during certain events (such as shortages that occur unexpectedly without sufficient notice for these offline units to be committed). ISO-NE is aware of these issues and evaluating potential solutions for addressing them.

Illustrative MRI and ELCC Approaches

MRI and ELCC approaches to capacity accreditation both rely on a probabilistic resource adequacy model that simulates LOLE or MWh of expected unserved energy. ISO-NE uses GE-MARS software to plan its capacity market requirements. MARS is a Monte Carlo model that inputs the system's resource mix and simulates a variety of load and resource outage conditions to estimate the likelihood of loss-of-load events.

Both MRI and ELCC approaches add or remove generation or load in MARS and simulate LOLE. The following are examples of generalized calculation approaches, although there are multiple variations of each approach:

Example MRI Approach. An example of an MRI calculation is as follows:

1. Begin with a base case simulation reflecting the expected system resource mix, with load increased so that LOLE = 0.1 days per year.
2. Add 50 MW of Resource X to (1). Calculate LOLE, which will be lower than 0.1 because the system will have more resources available.
3. Add 50 MW of perfect capacity to (1). Calculate LOLE, which will be lower than 0.1.

70 Output is measured during hour ending 14 through 18 in the Summer season (June through September), and hour ending 18 through 19 in the Winter season (October through May), plus any reserve shortage hours.

The MRI of Resource X is the ratio of the change in LOLE in step 2 to the change in LOLE in step 3: $MRI_X = (0.1 – LOLE_2) / (0.1 – LOLE_3)$. This will be less than or equal to 100 percent, because Resource X cannot be more reliable than perfect capacity.[71]

The same method may be employed if an alternative metric to LOLE, such as Expected Energy Not Served (EENS), is used. In this case, substitute EENS for LOLE in steps (2) and (3) and calculate the change in each step relative to EENS in step (1) accordingly.

Example ELCC Approach. ELCC methods determine how much load or perfect capacity could be replaced with a given quantity of Resource X while holding LOLE constant.[72] An example of an ELCC calculation, based on a recent proposal in PJM,[73] is as follows:

1. Begin with a base case simulation reflecting the expected system resource mix, including any MWs of Resource X. Increase load so that LOLE = 0.1 days per year.
2. Remove the capacity of Resource X from (1). LOLE will be above 0.1, because the system has less capacity and is therefore less reliable than (1).
3. Add perfect capacity to (2) until LOLE returns to 0.1.

The ELCC of Resource X is the quantity of perfect capacity added in (3) divided by the quantity of capacity of Resource X subtracted in (2). This percentage is less than or equal to 100 percent, because Resource X cannot be more reliable than perfect capacity.

A ***Marginal ELCC*** approach subtracts only a small quantity of Resource X in (2), while an ***Average ELCC*** approach subtracts all capacity of Resource X. For example, if 5,000 MW of Resource X already exists, marginal ELCC might consider how much load can be served by the next 50 to 100 MW of Resource X, while average ELCC would consider how much load can be served by all 5,000 MW. A 'portfolio ELCC' approach is similar to average ELCC but considers how much total load is served by a portfolio of multiple technologies simultaneously.

Comparison of MRI and ELCC Approaches

We recommend using MRI or Marginal ELCC to determine capacity accreditation. The key feature of these approaches is that they reflect a resource's marginal impact on LOLE, so they are consistent with ensuring reliability and with the principles of ISO-NE's capacity market.

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71 The number of resources added in the MRI simulation can vary but should be small enough so that it reflects an incremental change to the system as a whole. For example, our analysis of the NYISO market suggests that a size of 50 MW is small enough to calculate a marginal impact while producing an MRI function that is monotonic with the quantity of capacity in a given location.

72 There are many variations of ELCC methods, including whether the starting simulation is at or below criteria and the order in which the studied resource and perfect capacity or load are added/removed from the model. This section outlines one recent proposed approach. For a general description, see NERC, *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning*, March 2011.

73 This is a stylized simplification of PJM's proposal – see filings by PJM Interconnection L.L.C. in FERC Docket ER21-278-000, especially October 28, 2020 Affidavit of Dr. Patricio Rocha Garrido.

MRI and Marginal ELCC approaches are likely to produce very similar capacity credit results. Both approaches fundamentally consider how LOLE is affected by an incremental quantity of Resource X compared to an incremental quantity of perfect capacity. MRI is likely to be easier to implement because it requires a fixed number of MARS runs from a common base case (i.e., step 2 and step 3 make independently determined adjustments to the base case in step 1), while for ELCC MARS must be run iteratively (i.e., step 3 depends on the results of step 2, and determining the inputs to step 3 require some interpretation of the results of step 2). Thus, MRI methods can be automated, while ELCC methods would be difficult to fully automate.

Marginal approaches are preferable to average ELCC or heuristic approaches. ISO-NE's capacity market is designed based on a fundamental principle of economics—that prices reflect the marginal cost of serving demand so that suppliers have incentives to sell when their marginal cost is less than or equal to the marginal value to the system. Average ELCC methods divorce the payment an individual resource receives from its actual impact on reliability when choosing to enter the market, retire or repower. Hence, average ELCC methods can provide very inefficient investment incentives.

A marginal accreditation approach, therefore, offers several advantages:

(a) Investment signals – MRI and Marginal ELCC provide efficient signals for investment and retirement. As the resource mix evolves, these signals will be vital for guiding investment in clean resources. Marginal accreditation provides suppliers incentives to:

- Avoid technologies that have over-saturated the market by recognizing the diminishing reliability value of the technology. If an average or fixed credit is used, investors generally ignore this concern;
- Add resources that complement other types of resources on the system, such as adding storage onsite or separately to complement intermittent renewables. If an average or fixed credit is used, the incentive to do this is greatly diminished;
- Choose between storage projects with different durations by efficiently trading off cost and value to the system;
- Augment the duration of storage over time (for example, by adding more batteries to an existing project). If an average or fixed credit is used, the incentive to do this is greatly diminished;
- Efficiently repower renewable projects at the end of their useful lives;
- Efficiently retire or repower conventional units that are currently overvalued and maintain flexible dispatchable capacity that provides high reliability value.

(b) Avoids overpayment – marginal accreditation secures reliability at the lowest cost by paying each resource based on its marginal value to the system. Capacity prices, therefore, efficiently reflect the price needed to attract or retain capacity.

- This is analogous to the capacity market demand curve, which pays all resources a uniform clearing price based on the *marginal* value of the next MW of capacity.
- Average or portfolio ELCC approaches requires the procurement of more capacity (because some is overvalued), causing consumers to pay more in total for capacity.

Additional Features Required to Support Accreditation Methods

The MRI and Marginal ELCC methods can be used to determine accurate and efficient capacity accreditation values. This is because they align each resource type's accreditation with its impact on reliability in the ISO's resource adequacy model (MARS). This approach provides capacity accreditation values that (a) are consistent with the impact that each resource type has on the ICR, and (b) are the outcome of a modeling process that considers resources' availability and correlations at a detailed, hourly level. As a result, MARS can be used to effectively derive MRI or Marginal ELCC values for: intermittent resources, energy limited resources, hybrid resources, large units, and pipeline-only gas generators.

To support capacity accreditation based on MRI or ELCC approaches, additional efforts are needed to (1) ensure that the resource adequacy model produces accurate estimates of reliability value and (2) further adjust capacity credit values to account for features of some resources that affect reliability value but are not captured in MARS:

- The use of MARS to determine MRI or Marginal ELCC values requires that each resource type be modeled accurately in MARS. ISO-NE currently overestimates the reliability value of several resource types in MARS, including intermittent resources and gas-only resources. Issues with the modeling of these resources are described in Section IV of the report. These issues are largely related to the need to better model correlation of similar resources' availability and can be addressed through methodological changes within the existing MARS framework. Hence, we recommend that ISO-NE modify the resource adequacy model to enable accurate estimation of the marginal reliability value of different types of resources.
- Reliability value calculated using MARS may not sufficiently distinguish between expected availability of individual resources of the same type. Hence, in addition to MRI or Marginal ELCC values for each resource class and location, a separate adjustment to each individual resource's capacity accreditation may be needed reflecting its individual performance relative to other resources of the same type.
- MARS is not designed to consider unit commitment separately from dispatch. Therefore, it does not accurately estimate the reliability value of inflexible units, such as generators with long startup and notification times. It may not be possible to do so without fundamental changes to MARS. We encourage ISO-NE to explore whether this is possible but note that inflexible generators are especially vulnerable to pay-for-performance (PFP) penalties when flexibility-driven reserve shortages occur.

NEPOOL
NEW ENGLAND POWER POOL

19th Annual
Participants Committee Summer Meeting
Rockport, ME
June 23 Schedule   v. 2022.06.14**

SAMOSET RESORT ON THE OCEAN
CAMDEN-ROCKPORT-ROCKLAND, MAINE

SECTOR/GROUP	8:00 – 9:15 a.m.	9:30 – 10:45 a.m.	11:00 – 12:15 a.m.	12:15 – 2:00 p.m.
Generation / Long	State Officials Panel 1 ***(Camden)***	*FERC Staff (9:30-10:00)* ***(Schooner)***	ISO Board Panel 1 ***(Vinalhaven)***	Lunch (All) ***(Bay Point Ballroom)***
Transmission	State Officials Panel 2 ***(Rockland)***	*FERC Staff (10:10-10:40)* ***(Schooner)***	ISO Board Panel 2 ***(North Haven)***	
Supplier / Short (LSE)	*FERC Staff (8-8:30)* ***(Schooner)***	ISO Board Panel 2 ***(North Haven)***	State Officials Panel 1 ***(Camden)***	
Publicly Owned Entity	ISO Board Panel 2 ***(North Haven)***	State Officials Panel 2 ***(Rockland)***	*FERC Staff Date/Time TBD*	
AR	*FERC Staff (8:45-9:15)* ***(Schooner)***	ISO Board Panel 1 ***(Vinalhaven)***	State Officials Panel 2 ***(Rockland)***	
End User	ISO Board Panel 1 ***(Vinalhaven)***	State Officials Panel 1 ***(Camden)***	*FERC Staff Date/Time TBD*	
ISO Board Panel 1	End User ***(Vinalhaven)***	AR ***(Vinalhaven)***	Generation / Long ***(Vinalhaven)***	
ISO Board Panel 2	Publicly Owned Entity ***(North Haven)***	Supplier / Short (LSE) ***(North Haven)***	Transmission ***(North Haven)***	
State Officials Panel 1	Generation / Long ***(Camden)***	End User ***(Camden)***	Supplier / Short (LSE) ***(Camden)***	
State Officials Panel 2	Transmission ***(Rockland)***	Publicly Owned Entity ***(Rockland)***	AR ***(Rockland)***	
FERC Staff	Supplier/Short (LSE) *(8-8:30)* *AR (8:45-9:15)* ***(Schooner)***	*Generation/Long (9:30-10:00)* *Transmission (10:10-10:40)* ***(Schooner)***	*End User & POE Date/Time TBD*	

ISO Board Panel 1: Brook Colangelo, Mike Curran, Catherine Flax, Cheryl LaFleur, and Gordon van Welie.

ISO Board Panel 2: Caren Anders, Steve Corneli, Roberto Denis, Barney Rush, Mark Vannoy, and Vickie VanZandt.

State Officials Panel 1: TBD. **

State Officials Panel 2: TBD. **

FERC Staff: Nicole Businelli, Noah Schlosser [Date & Times with End User and POE Sectors TBD]

**** Subject to change**