NEW ENGLAND POWER POOL
David T. Doot
Secretary

June 18, 2019

VIA ELECTRONIC MAIL

TO: MEMBERS AND ALTERNATES OF THE NEPOOL PARTICIPANTS COMMITTEE

RE: Supplemental Notice of June 25-27, 2019 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 25-27, 2019 at Gurney's Resort in Newport, RI. Please see the attached meeting agenda and Sector meeting schedule, which are also posted with the meeting materials. If you have not already registered for the meeting, please do so ***ASAP*** using the link from the Summer Meeting Information page on the NEPOOL website. Plenary sessions will be in the Grand Ballroom. Telephone participation will be available for the plenary sessions (but not the separate meetings of the modified Sector groups) if you contact us for the dial-in information.

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.

We encourage those of you who arrive next Monday evening to join your colleagues at a dessert/coffee reception from 8:00-10:00 p.m. The general business portion of the meeting is on Tuesday. **The first agenda item presently is planned to start at 8:30 a.m. in general session, followed by discussion in confidential executive session solely among *members and alternate members or their delegates*, to discuss a proposal to adjust the age limitation for the ISO Board members.** For the remainder of Tuesday's meeting, the general session is expected to begin at 9:00 a.m. Note that Tuesday's agenda also includes remarks from FERC Commissioner Cheryl LaFleur and reports by both the ISO's Internal Market Monitor and the External Market Monitor. Wednesday's session also is planned to begin at 8:30 a.m. for an extended discussion among ISO Board members and management, Participants, and State Officials on energy security challenges and on the evolution of the wholesale markets in light of changing technologies and public policies and priorities of the six New England States. Wednesday afternoon is set aside for separate meetings or participation in networking events. Thursday's session is for modified Sector group meetings, rather than a continued Participants Committee meeting. Those modified Sector group meetings are scheduled to begin at 8:00 a.m., with times set aside for each group to meet separately with State Officials and ISO Board members. ***Please note when and where your modified Sector group is scheduled to meet.*** Additional information regarding the Summer Meeting is available on the NEPOOL Summer Meeting Page at http://nepool.com/Summer_Mtg_Info_Page.php.

If you have not already done so***, please register now.*** The NEPOOL reservations block at Gurney's is now closed, but if you have not yet made your reservation and contact Cindy Jacobs, she may be able to assist getting you into Gurney's or an alternative venue/inn if possible. **For those staying at Gurney's, 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 48 hours prior to the first day of your reservation. Dress for the Summer Meeting is business casual.**

Respectfully yours,

/s/
David T. Doot, Secretary

FINAL AGENDA

TUESDAY, JUNE 25, 2019

8:30-9:00 a.m.* Includes Confidential Executive Session
9:00 a.m. – 4:30 p.m.* General Session

During Tuesday's general session we will receive remarks from FERC Commissioner Cheryl LaFleur immediately following lunch.

Item 1 on the Initial Agenda will be introduced in general session, but the Committee will then hold discussion in executive session, during which participation will be limited exclusively to voting Members and Alternates or their designates.

1. To consider in part in executive session proposed changes to the Participants Agreement regarding the age limit for ISO New England Board members, and take action as appropriate. A proposed draft of changes reflecting comments from members, along with supporting background materials and a draft resolution are included with this supplemental notice and posted with the meeting materials.

The Initial Agenda for general business portion of the meeting includes the following:

2. To approve the preliminary minutes of the Participants Committee meeting held on May 3, 2019. The draft minutes of the May 3 meeting, marked to show changes from the draft circulated with the initial notice, are included with this supplemental notice and posted with the meeting materials.
3. To adopt and approve all actions recommended by the Technical Committees set forth on the Consent Agenda included with this supplemental notice and posted on the NEPOOL website.
4. To consider and take action, as appropriate, on ISO's proposed Tariff changes to accommodate nested export constrained capacity zones in the FCM. Background materials and a draft resolution are included with this supplemental notice and posted with the meeting materials.
5. To receive a Chief Executive Officer Report by Gordon van Welie, ISO New England.
6. To receive a Chief Operations Officer Report by Dr. Vamsi Chadalavada, ISO New England. The COO report reflecting May data was circulated previously and is posted with the composite meeting materials.
7. To receive a FERC update from a FERC representative.
8. To receive a report on the ISO's preliminary 2020 and 2021 Operating and Capital Budgets by Chief Financial & Compliance Officer Robert Ludlow, ISO New England. A PowerPoint presentation is included with this supplemental notice and posted with the meeting materials.
9. To receive an Internal Market Monitor Report by Dr. Jeffrey McDonald, ISO New England. Dr. McDonald's annual report was circulated previously and is posted with the composite meeting materials.
10. To consider and take action, as appropriate, on Participant-proposed revisions to the ISO Financial Assurance Policy (FAP) and ISO Billing Policy to permit affiliate parent guarantees and surety bonds. Background materials and a draft resolution are included with his supplemental notice and posted with the meeting materials.

10A. To consider and take action, as appropriate, on a recommendation by the Membership Subcommittee to amend the definition of Gas Industry Participant (to be renamed "Fuels Industry Participant") and to approve American Petroleum Institute as a Fuels Industry Participant. Background material and a draft resolution are included with this supplemental notice and posted with the meeting materials.

11. [REMOVED AT PROPONENT'S REQUEST]~~To consider and take action, as appropriate, on Participant-proposed revisions to the FAP requirements for Non-Commercial Capacity.~~

*All start and finish times subject to adjustment.

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

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

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

14. To receive an External Market Monitor Report by Dr. David Patton, President, Potomac Economics. A presentation with highlights of the EMM's 2018 Annual Report on the ISO New England Markets will be circulated and posted following receipt.

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

WEDNESDAY, JUNE 26, 2019
8:30 a.m. – 12:00 p.m.*

16. To receive welcome remarks.

17. To hear reports and discuss the efforts that will be required over time to operate the power grid, maintain reliability, and evolve organized wholesale power markets elsewhere, and here, in light of changing technologies, public policies and priorities.

A. Operating the Grid in the UK and Lessons for New England:

- **Mike Calviou**, Senior Vice President-Strategy and Regulation, National Grid, will present on the fuel/energy security challenges facing the UK grid operator and the group will then discuss relevant similarities and differences between the UK and New England grids in defining market solutions.

B. Evolving Markets and Public Policy in New England:

- **Sharon Reishus**, President, Reishus Consulting, and former Chair of the Maine PUC, will moderate a discussion among attendees, which will be introduced by the following panelists who will present their observations about policy and market challenges facing the industry:
- **Travis Kavulla**, Director of Energy and Environmental Policy at the R Street Institute and a former Chairman of the Montana Public Service Commission and former President of NARUC.
- **Ari Peskoe,** Director of the Electricity Law Institute at Harvard Law School.
- Wrap-up and moderated discussion.

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

THURSDAY, JUNE 27, 2019
8:00 a.m. – 12:15 p.m.*

To participate in separate meetings of modified Sectors with individual Board Members and State Officials, as detailed in the Sector meeting schedule included with this agenda.

*All start and finish times subject to adjustment.

NEPOOL
NEW ENGLAND POWER POOL

18th Annual
Participants Committee Summer Meeting
Newport, RI
June 27 Schedule**

Gurney's NEWPORT

SECTOR/GROUP	8:00 – 9:15	9:30 – 10:45	11:00 – 12:15	12:15 – 2:00
Generation / Long	State Officials Panel 1 ***(Ballroom D)***	*Open*	ISO Board Panel 1 ***(Vanderbilt)***	Lunch (All) ***(Rose Island)***
Transmission	*Open*	State Officials Panel 2 ***(Ballroom C)***	ISO Board Panel 2 ***(Heritage)***	
Supplier / Short (LSE)	ISO Board Panel 2 ***(Heritage)***	*Open*	State Officials Panel 1 ***(Ballroom D)***	
Publicly Owned Entity	State Officials Panel 2 ***(Ballroom C)***	ISO Board Panel 2 ***(Heritage)***	*Open*	
AR	*Open*	ISO Board Panel 1 ***(Vanderbilt)***	State Officials Panel 2 ***(Ballroom C)***	
End User	ISO Board Panel 1 ***(Vanderbilt)***	State Officials Panel 1 ***(Ballroom D)***	*Open*	
ISO Board Panel 1	End User ***(Vanderbilt)***	AR ***(Vanderbilt)***	Generation / Long ***(Vanderbilt)***	
ISO Board Panel 2	Supplier / Short (LSE) ***(Heritage)***	Publicly Owned Entity ***(Heritage)***	Transmission ***(Heritage)***	
State Officials Panel 1	Generation / Long ***(Ballroom D)***	End User ***(Ballroom D)***	Supplier / Short (LSE) ***(Ballroom D)***	
State Officials Panel 2	Publicly Owned Entity ***(Ballroom C)***	Transmission ***(Ballroom C)***	AR ***(Ballroom C)***	

ISO Board Panel 1: Brook Colangelo, Mike Curran, Raymond Hill, Philip Shapiro, and Gordon van Welie.

ISO Board Panel 2: Kathleen Abernathy, Roberto Denis, Barney Rush, Vickie VanZandt, and Christopher Wilson.

State Officials Panel 1: RI Chair Curran, NH Commissioner Giaimo, MA Chair Nelson, VT Commissioner Tierney, VT Chair Roisman, CT Commissioner Dykes, VT Staff Mary-Jo Krolewski, ME Staff Denis Bergeron, NESCOE Staff Jeff Bentz, NESCOE Staff Ben D'Antonio, and NECPUC Staff Rachel Goldwasser. **

State Officials Panel 2: CT Chair Gillett, RI Dept'y Commissioner Ucci, NH Commissioner Bailey, ME Chair Bartlett, VT Commissioner Hofmann, MA Staff Sheila Keane, VT Staff Ed McNamara, CT Staff Eric Annes, NESCOE Staff Dorothy Capra, NESCOE Staff Jason Marshall, and NESCOE Staff Heather Hunt. **

**** Subject to change**

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Paul Belval, NEPOOL Counsel

DATE: June 18, 2019

RE: Participant-Sponsored Proposal: Addition of Affiliate Guarantees and Surety Bonds to ISO-NE Financial Assurance Policy

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At its June 25, 2019 summer meeting, the Participants Committee will be asked to consider a proposal reflecting Participant-sponsored changes to the ISO New England Financial Assurance Policy ("FAP") that would (1) permit Market Participants to rely on an affiliate guaranty as a means of obtaining an unsecured Market Credit Limit or Transmission Credit Limit and (2) add surety bonds as an acceptable form of financial assurance. The proposal is sponsored by Calpine Energy Services, LP, Direct Energy Business, LLC, Dominion Energy Generation Marketing, Inc., Exelon Generation Company, LLC, Massachusetts Municipal Wholesale Electric Company, NextEra Energy Resources, LLC and PSEG Energy Resources & Trade LLC (collectively, the "Sponsors").

This memorandum provides information on this proposal, including background on discussions at the Budget and Finance Subcommittee (the "Subcommittee"). A summary of the proposal is included as Attachment 1, and the proposed changes to the FAP, including the proposed forms of surety bond and guarantees, are included as Attachment 2. The ISO is opposed to the proposal, and a memorandum from the ISO explaining its opposition to the proposal is included as Attachment 3.

Prior versions of the FAP included parent guarantees and surety bonds as acceptable forms of financial assurance for Market Participants required to provide financial assurance. Surety bonds were eliminated in 2004, and parent guarantees were eliminated in 2010, in each case with the support of the Participants Committee.

The proposal before the Participants Committee would allow a qualified Market Participant to rely on affiliate guarantees as a means of establishing an unsecured Credit Limit or meeting the capitalization requirements under the FAP and to use surety bonds as a form of financial assurance. In support of the proposed changes, the Sponsors have noted that several of the other RTOs permit market participants to use a guaranty to either establish an unsecured credit limit or to satisfy the capitalization requirement for members.[1] In addition, NYISO and ERCOT permit market participants to use surety bonds as a form of financial assurance. PJM is currently considering surety bonds as well. The Sponsors also said that the two forms of financial assurance currently permitted under the FAP – cash deposits and letters of credit – are

[1] NYISO, PJM, MISO, SPP, ERCOT and CAISO permit the use of a corporate guaranty in their credit policies.

more costly to Market Participants than corporate guarantees and surety bonds, and those increased costs are ultimately imposed on the ISO markets. ISO-NE indicated its opposition to this at the Subcommittee, expressing concerns that the ISO-NE may not receive payment on a guaranty or surety bond quickly enough to settle the markets in each billing cycle without a payment default. The Sponsors pointed out that the proposed forms of guarantees and surety bonds require next day payment.[2]

The Subcommittee discussed the Sponsors' proposal at its November 27, February 14, March 28, April 18 and May 10 teleconferences. The Subcommittee is not a voting group, and as such, did not take a vote on this proposal. In addition to the ISO's concern about prompt settlement, some Subcommittee members noted that only Market Participants that were part of a corporate group can provide an affiliate guaranty from a creditworthy entity. With respect to surety bonds, some Subcommittee members argued that surety bonds are only available to well-capitalized Market Participants.

The following form of resolution may be used for the Participants Committee action requested by the Sponsors:

> RESOLVED, that the Participants Committee supports revisions to the ISO New England Financial Assurance Policy, as proposed by Calpine Energy Services, LP, Direct Energy Business, LLC, Dominion Energy Generation Marketing, Inc., Exelon Generation Company, LLC, Massachusetts Municipal Wholesale Electric Company, NextEra Energy Resources, LLC and PSEG Energy Resources & Trade LLC and as circulated to this Committee with the June 18, 2019 supplemental notice, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

[2] See Section 4 of each form Guaranty and Section 2.03 of the form Surety Bond.

Summary of Proposed Changes to ISO New England Financial Assurance Policy

Note: Capitalized terms have the meanings given to them in the ISO New England ("ISO-NE") Financial Assurance Policy ("FAP") or the ISO-NE Tariff.

Guarantees

- For any Market Participant that does not satisfy the credit rating or Credit Threshold requirements for an unsecured Market Credit Limit or Transmission Credit Limit, that Market Participant can obtain such a Credit Limit by providing a corporate guaranty from a Guarantor satisfying those requirements in the following circumstances:
  - If the Guarantor is organized under the laws of the U.S., it must be an Affiliate of the Market Participant for which it provides a corporate guaranty.
    - The obligations of a Municipal Market Participant that is a member of a cooperative, joint action agency or similar entity can be guaranteed by that cooperative, joint action agency or similar entity so long as it is also a Market Participant, even if the two are not Affiliates.
    - If the Guarantor is organized under the laws of a Canadian jurisdiction, it must satisfy the requirements for a U.S. Guarantor and must also provide the financial statements required under the Financial Assurance Policy in English in accordance with GAAP or international financial reporting standards.
  - If the Guarantor is organized under the laws of another country, it must satisfy the requirements for a Canadian Guarantor and the following additional requirements:
    - Domiciled in a country with a minimum long-term sovereign rating of AA+/Aa1, and that recognizes and enforces judgments of U.S. state and federal courts;
    - Appoints an agent in Massachusetts for the acceptance of service of process;
    - Has either American Depository Receipts traded on the New York Stock Exchange, American Stock Exchange or NASDAQ, or has equity ownership over $100 million in wholly owned or majority owned subsidiaries organized under the laws of a jurisdiction of the U.S.; and
    - Provides the ISO with an opinion of legal counsel, in form and substance acceptable to the ISO in its sole discretion.
- A corporate guaranty can also be used to satisfy the capitalization requirements of the Financial Assurance Policy.
- A Guarantor, Canadian Guarantor or Foreign Guarantor may not guaranty more than $50 million of obligations in the aggregate.
- If the amount of the guaranty is further capped by the Guarantor, Canadian Guarantor or Foreign Guarantor below that $50 million limit, then the aggregate credit limits cannot exceed that lower cap.
- If the Guarantor, Canadian Guarantor or Foreign Guarantor no longer satisfies the requirements to provide a corporate guaranty, or if the corporate guaranty terminates or is not renewed at least 30 days prior to its expiration date, then the Market Participant must provide another acceptable form of financial assurance.
- A Financial Assurance Default will occur if the Guarantor, Canadian Guarantor or Foreign Guarantor breaches the corporate guaranty or if the corporate guaranty is terminated or challenged by the Guarantor, Canadian Guarantor or Foreign Guarantor.
- The acceptable form of corporate guaranty from a U.S. Guarantor includes the following:
  - Possible cap on aggregate amount guaranteed

- Limited term and Guarantor can terminate on 60 days' notice, but all amounts due prior to termination are covered
- Payments due by 5 p.m. on the business day after the ISO makes a demand for payment
- Demand can only be made against Guarantor after Market Participant has failed to make payment
- Guarantor pays all expenses incurred to enforce corporate guaranty
- Guarantor provides all financial statements required under the Financial Assurance Policy

o The acceptable form of corporate guaranty from a Canadian Guarantor or Foreign Guarantor includes the same provisions as a U.S. Guarantor, and also includes the following:
  - Payments must be in U.S. dollars to an ISO account in the U.S.
  - Payments must be increased to the extent required to account for withheld taxes
  - Guarantor acknowledges Massachusetts governing law

<u>Surety Bonds</u>

o Surety bond meeting the requirements of the Financial Assurance Policy is an acceptable form of financial assurance.
o The surety bond must be payable immediately upon demand and must have a duration of at least one year.
o Surety must (i) be a U.S. Treasury-listed approved surety and (2) maintain a minimum rating of "A-/A3" by S&P, Moody's, Fitch and/or A.M. Best.
o Surety cannot be an Affiliate of the Posting Entity.
o No surety may issue surety bonds in an amount exceeding either (i) $20 million in the aggregate for any single Posting Entity; or (ii) $100 million in the aggregate for a group of Posting Entities that are Affiliates; or (iii) $100 million in the aggregate for surety bonds from the same surety.
o If surety fails to honor the terms of surety bond twice in a rolling 730-day period, it will no longer be eligible to provide surety bonds.
o Acceptable form of surety bond includes the following terms:
  - Payment by the surety is not conditioned on the ISO first seeking payment from the Market Participant.
  - The surety must pay to the ISO all or any portion of the Obligations on or before 5 p.m., local time in Holyoke, MA on the first business day following notice from the ISO that Market Participant has failed to meet any of the Obligations.
  - The surety bond will automatically renew annually, unless the surety provides at least a 60-day notice to terminate such bond. If Market Participant fails to provide an acceptable form of replacement security to the ISO at least 50 days prior to the termination of the bond, the surety must deliver, upon demand from ISO, cash collateral in the amount of the full remaining value of such bond as security. Any such cash collateral not applied by ISO to satisfy unpaid Obligations will be returned to the surety at such time as (i) Market Participant provides adequate replacement security or (ii) Market Participant ceases to be an ISO customer and all amounts owed by Market Participant to the ISO are paid in full.
  - The surety waives certain defenses, and waives all rights to set-off amounts due by the ISO to Market Participant.
  - Market Participant pays all costs and fees for the surety bond.

EXHIBIT IA

ISO NEW ENGLAND FINANCIAL ASSURANCE POLICY

Table of Contents

satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy).

Any customer or applicant that does not satisfy any of the criteria listed above but has a Guarantor, Canadian Guarantor or Foreign Guarantor (each defined below) that satisfies those criteria may meet these capitalization requirements by providing a corporate guaranty by such Guarantor, Canadian Guarantor or Foreign Guarantor guaranteeing all of the obligations of such customer or applicant. Such Guarantor, Canadian Guarantor or Foreign Guarantor and such corporate guaranty shall satisfy all of the requirements of Section II.H. If at any time such Guarantor, Canadian Guarantor or Foreign Guarantor or such corporate guaranty ceases to satisfy the criteria listed above or any of the requirements of Section II.H, such customer or applicant must thereafter satisfy one of the other criteria set forth above in order to meet these capitalization requirements.

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

(c) For markets other than the FTR market:

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

to establish a Market Credit Limit or a Transmission Credit Limit of greater than $0 under Section II.D or Section II.E below must submit to the ISO all current rating agency reports from Standard and Poor's ("S&P"), Moody's and/or Fitch (collectively, the "Rating Agencies"). Each Applicant that is relying on a corporate guaranty to satisfy the capitalization requirements listed in Section II.A.4 or is relying on a corporate guaranty to establish a Market Credit Limit or a Transmission Credit Limit of greater than zero under Section II.D or Section II.E must provide all information required to establish that the Guarantor, Canadian Guarantor or Foreign Guarantor satisfies all of the requirements of a Guarantor, Canadian Guarantor or Foreign Guarantor under this Policy. In addition, each Applicant, whether or not it intends to establish a Market Credit Limit or Transmission Credit Limit of greater than $0, must submit to the ISO audited financial statements for the two most recent years, or the period of its existence, if less than two years, and unaudited financial statements for its last concluded fiscal quarter if they are not included in such audited annual financial statements. These unaudited statements must be certified as to their accuracy by a Senior Officer of such Applicant, which, for purposes of ISO New England Financial Assurance Policy, means an officer of the subject entity with the title of vice president (or similar office) or higher, or another officer designated in writing to the ISO by that officer. These audited and unaudited statements must include in each case, but are not limited to, the following information to the extent available: balance sheets, income statements, statements of cash flows and notes to financial statements, annual and quarterly reports, and 10-K, 10-Q and 8-K Reports. If any of these financial statements are available on the internet, the Applicant may provide instead a letter to the ISO stating where such statement may be located and retrieved. If any of the information or documentation required by this section is not available, alternate requirements may be specified by the ISO, at the ISO's sole discretion (such alternate requirements may include, but are not limited to: (i) consolidating statements or other financial statements (in the case of a stand-alone subsidiary) that are certified as to their accuracy and basis of accounting (in accordance with international accounting standards or generally accepted accounting principles in the United States) by an officer of the entity with the title of chief financial officer or equivalent position; (ii) reviewed statements; or (iii) compiled statements).

In addition, each Applicant, whether or not it intends to establish a Market Credit Limit or a Transmission Credit Limit, must submit to the ISO: (i) at least one (1) bank

reference and three (3) utility company credit references, or in those cases where an Applicant does not have three (3) utility company credit references, three (3) major trade payable vendor references may be substituted; and (ii) relevant information as to any known or anticipated material lawsuits, as well as any prior bankruptcy declarations by the Applicant, or by its predecessor(s), if any; and (iii) a completed ISO credit application. In the case of certain Applicants, some of the information and documentation described in items (i) and (ii) of the immediately preceding sentence may not be applicable or available, and alternate requirements may be specified by the ISO or its designee in its sole discretion.

The ISO will not begin its review of a Market Participant's credit application or the accompanying material described above until full and final payment of that Market Participant's application fee.

The ISO shall prepare a report, or cause a report to be prepared, concerning the financial viability of each Applicant. In its review of each Applicant, the ISO or its designee shall consider all of the information and documentation described in this Section II. All costs incurred by the ISO in its review of the financial viability of an Applicant shall be borne by such Applicant and paid at the time that such Applicant is required to pay its first annual fee under the Participants Agreement. For an Applicant applying for transmission service from the ISO, all costs incurred by the ISO shall be paid prior to the ISO's filing of a Transmission Service Agreement. The report shall be provided to the Participants Committee or its designee and the affected Applicant within three weeks of the ISO's receipt of that Applicant's completed application, application fee, and Initial Market Participant Financial Assurance Requirement, unless the ISO notifies the Applicant that more time is needed to perform additional due diligence with respect to its application.

C. Ongoing Review and Credit Ratings

1. Rated and Credit Qualifying Market Participants, Guarantors, Canadian Guarantors and Foreign Guarantors

A Market Participant, Guarantor, Canadian Guarantor or Foreign Guarantor that (i) has a corporate rating from one or more of the Rating Agencies, or (ii) has senior unsecured debt that is rated by one or more of the Rating Agencies, is referred to herein as "Rated."

A Market Participant, Guarantor, Canadian Guarantor or Foreign Guarantor that is not Rated is referred to herein as "Unrated."

For all purposes in the ISO New England Financial Assurance Policy, for a Market Participant, Guarantor, Canadian Guarantor or Foreign Guarantor that is Rated, the lowest corporate rating from any Rating Agency for that Market Participant, or, if the Market Participant has no corporate rating, then the lowest rating from any Rating Agency for that Market Participant's senior unsecured debt, shall be the "Governing Rating."

A Market Participant that is: (i) Rated and whose Governing Rating is an Investment Grade Rating; or (ii) Unrated and that satisfies the Credit Threshold or (iii) has a Market Credit Limit or Transmission Credit Limit greater than zero due to a Guarantor, Canadian Guarantor or Foreign Guarantor posting a corporate guaranty on its behalf is referred to herein as "Credit Qualifying."[1] A Market Participant that is not Credit Qualifying is referred to herein as "Non-Qualifying."

For purposes of the ISO New England Financial Assurance Policy, "Investment Grade Rating" for a Market Participant (other than an FTR-Only Customer) ~~or~~, Non-Market Participant Transmission Customer, Guarantor, Canadian Guarantor or Foreign Guarantor is either (a) a corporate investment grade rating from one or more of the Rating Agencies, or (b) if the Market Participant ~~or~~, Non-Market Participant Transmission Customer, Guarantor, Canadian Guarantor or Foreign Guarantor does not have a corporate rating from one of the Rating Agencies, then an investment grade rating for the Market Participant's ~~or~~, Non-Market Participant Transmission Customer's, Guarantor's, Canadian Guarantor's or Foreign Guarantor's senior unsecured debt from one or more of the Rating Agencies.

2. Unrated Market Participants

Any Unrated Market Participant that (i) has not been a Market Participant in the ISO for at least the immediately preceding 365 days; or (ii) has defaulted on any of its obligations under the Tariff (including without limitation its obligations hereunder and under the ISO

[1] Ntd: Need to make this change in the definitions in the Tariff as well.

New England Billing Policy) during such 365-day period; or (iii) is an FTR-Only Customer; or (iv) does not have a Current Ratio of at least 1.0, a Debt-to-Total Capitalization Ratio of 0.6 or less, and an EBITDA-to-Interest Expense Ratio of at least 2.0 must provide an appropriate form of financial assurance as described in Section X below. An Unrated Market Participant that does not meet any of the conditions in clauses (i), (ii), (iii) and (iv) of this paragraph is referred to herein as satisfying the "Credit Threshold." Any Guarantor, Canadian Guarantor or Foreign Guarantor that has a Current Ratio of at least 1.0, a Debt-to-Total Capitalization Ratio of 0.6 or less, and an EBITDA-to-Interest Expense Ratio of at least 2.0 is referred to herein as satisfying the Credit Threshold.

For purposes of the ISO New England Financial Assurance Policy, "Current Ratio" on any date is all of a Market Participant's ~~or~~, Non-Market Participant Transmission Customer's, Guarantor's, Canadian Guarantor's or Foreign Guarantor's current assets divided by all of its current liabilities, in each case as shown on the most recent financial statements provided by such Market Participant ~~or~~, Non-Market Participant Transmission Customer, Guarantor, Canadian Guarantor or Foreign Guarantor to the ISO; "Debt-to-Total Capitalization Ratio" on any date is a Market Participant's ~~or~~, Non-Market Participant Transmission Customer's, Guarantor's, Canadian Guarantor's or Foreign Guarantor's total debt (including all current borrowings) divided by its total shareholders' equity plus total debt, in each case as shown on the most recent financial statements provided by such Market Participant ~~or~~, Non-Market Participant Transmission Customer, Guarantor, Canadian Guarantor or Foreign Guarantor to the ISO; and "EBITDA-to-Interest Expense Ratio" on any date is a Market Participant's ~~or~~, Non-Market Participant Transmission Customer's, Guarantor's, Canadian Guarantor's or Foreign Guarantor's earnings before interest, taxes, depreciation and amortization in the most recent fiscal quarter divided by that Market Participant's ~~or~~, Non-Market Participant Transmission Customer's, Guarantor's, Canadian Guarantor's or Foreign Guarantor's expense for interest in that fiscal quarter, in each case as shown on the most recent financial statements provided by such Market Participant ~~or~~, Non-Market Participant Transmission Customer, Guarantor, Canadian Guarantor or Foreign Guarantor to the ISO. The "Debt-to-Total Capitalization Ratio" will not be considered for purposes of determining whether a Municipal Market Participant satisfies the Credit Threshold. Each of the ratios described in this paragraph shall be determined in accordance with international

accounting standards or generally accepted accounting principles in the United States at the time of determination consistently applied.

3. Information Reporting Requirements for Market Participants

Each Market Participant having a Market Credit Limit or Transmission Credit Limit greater than zero or meeting the capitalization requirements by maintaining a minimum Tangible Net Worth or minimum total assets as described in Section II.A.4(a) and each Guarantor, Canadian Guarantor or Foreign Guarantor providing a corporate guaranty under the ISO New England Financial Assurance Policy shall submit to the ISO, on a quarterly basis within 10 days of its becoming available and within 65 days after the end of the applicable fiscal quarter of such Market Participant, Guarantor, Canadian Guarantor or Foreign Guarantor its balance sheet, which shall show sufficient detail for the ISO to assess the Market Participant's, Guarantor's, Canadian Guarantor's or Foreign Guarantor's Tangible Net Worth. Unrated Market Participants having a Market Credit Limit or Transmission Credit Limit greater than zero and Unrated Guarantors, Canadian Guarantors and Foreign Guarantors providing a corporate guaranty under the ISO New England Financial Assurance Policy shall also provide additional financial statements, which shall show sufficient detail for the ISO to calculate such Unrated Market Participant's Current Ratio, Debt-to-Total Capitalization Ratio and EBITDA-to-Interest Expense Ratio. In addition, each Market Participant having a Market Credit Limit or Transmission Credit Limit greater than zero or meeting the capitalization requirements by maintaining a minimum Tangible Net Worth or minimum total assets as described in Section II.A.4(a) and each Guarantor, Canadian Guarantor or Foreign Guarantor providing a corporate guaranty under the ISO New England Financial Assurance Policy shall submit to the ISO, annually within 10 days of their becoming available and within 120 days after the end of the fiscal year of such Market Participant, Guarantor, Canadian Guarantor or Foreign Guarantor, balance sheets and income statements (balance sheets and income statements that are part of audited financial statements shall be submitted if available; if such balance sheets and income statements are not available, then, solely with respect to a Market Participant, another alternative form of financial statements accepted by the ISO as described below may be submitted). If any of this financial information is available on the internet, the Market Participant may provide instead a letter to the ISO stating where such information may be located and retrieved. If any of the information or documentation required by this section is not available, alternate

requirements may be specified by the ISO for a Market Participant, but not for a Guarantor, Canadian Guarantor or Foreign Guarantor (such alternate requirements for Market Participants may include, but are not limited to: (i) consolidating statements or other financial statements (in the case of a stand-alone subsidiary) that are certified as to their accuracy and basis of accounting (in accordance with international accounting standards or generally accepted accounting principles in the United States) by an officer of the entity with the title of chief financial officer or equivalent position; (ii) reviewed statements; (iii) compiled statements; (iv) internally prepared statements; or (v) tax returns).

Except in the case of a Market Participant ~~or Unrated Market Participant~~, Guarantor, Canadian Guarantor or Foreign Guarantor that submits audited financial statements to the ISO, financial statements submitted to the ISO pursuant to this Section II.C.3 shall be accompanied by a written statement from a Senior Officer of the Market Participant ~~or Unrated Market Participant~~, Guarantor, Canadian Guarantor or Foreign Guarantor certifying the accuracy of those financial statements. If an attestation was made by an independent accounting firm, then the written statement shall indicate the level of attestation made; if no attestation was made by an independent accounting firm, then no such indication is required.

Notwithstanding any other provision in this subsection, the ISO may require any Market Participant to submit the financial statements and other information described in this subsection. The Market Participant shall provide the requested statements and other information within 10 days of such request. If a Market Participant fails to provide financial statements or other information as requested and the ISO determines that the Market Participant poses an unreasonable risk to the New England Markets, then the ISO may request that the Market Participant provide additional financial assurance in an amount no greater than $10 million, or take other measures to substantiate the Market Participant's ability to safely transact in the New England Markets (any additional financial assurance provided pursuant to this Section II.C.3 shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy). If the Market Participant fails to comply with such a request from the ISO, then the ISO may issue a notice of suspension or termination to the Market Participant. If the Market Participant fails to comply with the

ISO's request within 5 Business Days from the date of issuance of the notice of suspension or termination, then the ISO may suspend or terminate the Market Participant.

A Market Participant may choose not to submit financial statements as described in this Section II.C.3, in which case the ISO shall use a value of $0.00 for the Market Participant's total assets and Tangible Net Worth for purposes of the capitalization assessment described in Section II.A.4(a) and such Market Participant's Market Credit Limit and Transmission Credit Limit shall be $0.00.

A Market Participant may choose to provide additional financial assurance in an amount equal to $10 million in lieu of providing financial statements under this Section II.C.3. Such amount shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy but shall be sufficient to meet the capitalization requirements in Section II.A.4(a)(iii).

D. Market Credit Limits

A credit limit for a Market Participant's Financial Assurance Obligations except FTR Financial Assurance Requirements (a "Market Credit Limit") shall be established for each Market Participant in accordance with this Section II.D.

1. Market Credit Limit for Non-Municipal Market Participants

A "Market Credit Limit" shall be established for each Rated Non-Municipal Market Participant in accordance with subsection (a)~~ below~~, and a Market Credit Limit shall be established for each Unrated Non-Municipal Market Participant in accordance with subsection (b) and Section II.H below.

a. Market Credit Limit for Rated Non-Municipal Market Participants

As reflected in the following table, the Market Credit Limit of each Rated Non-Municipal Market Participant (other than an FTR-Only Customer) shall at any time be equal to the lesser of: (i) the applicable percentage of such Rated Non-Municipal Market Participant's Tangible Net Worth as listed in the following table, (ii) $50 million, or (iii) 20 percent (20%) of the total amount due and owing (not including any amounts due under Section 14.1 of the RNA) at such time to the ISO, NEPOOL, the PTOs, the Market Participants

b. Market Credit Limit for Unrated Non-Municipal Market Participants

The Market Credit Limit of each Unrated Non-Municipal Market Participant that satisfies the Credit Threshold shall at any time be equal to the lesser of: (i) 0.50 percent (0.50% or ½ of 1%) of such Unrated Non-Municipal Market Participant's Tangible Net Worth, (ii) $25 million or (iii) 20 percent (20%) of TADO. The Market Credit Limit of each Unrated Non-Municipal Market Participant that does not satisfy the Credit Threshold shall be $0.

2. Market Credit Limit for Municipal Market Participants

A Market Credit Limit shall be established for each Credit Qualifying Municipal Market Participant and each Non-Qualifying Municipal Market Participant in accordance with this Section and Section II.H. below. The Market Credit Limit for each Credit Qualifying Municipal Market Participant shall be equal to the lesser of (i) 20 percent (20%) of TADO and (ii) $25 million. The Market Credit Limit for each Non-Qualifying Municipal Market Participant shall be $0. The sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates or have provided a corporate guaranty from the same Guarantor, Canadian Guarantor or Foreign Guarantor shall not exceed $50 million.

E. Transmission Credit Limits

A "Transmission Credit Limit" shall be established for each Market Participant in accordance with this Section II.E and Section II.H, which Transmission Credit Limit shall apply in accordance with this Section II.E. A Transmission Credit Limit may not be used to meet FTR Financial Assurance Requirements.

1. Transmission Credit Limit for Rated Non-Municipal Market Participants

The Transmission Credit Limit of each Rated Non-Municipal Market Participant shall at any time be equal to the lesser of: (i) the applicable percentage of such Rated Non-Municipal Market Participant's Tangible Net Worth as listed in the following table or (ii) $50 million:

Investment Grade Rating		Percentage of Tangible Net Worth
S&P/Fitch	**Moody's**	

AAA	Aaa	5.50%
AA+	Aa1	5.50%
AA	Aa2	4.50%
AA-	Aa3	4.00%
A+	A1	3.05%
A	A2	2.85%
A-	A3	2.60%
BBB+	Baa1	2.30%
BBB	Baa2	1.90%
BBB-	Baa3	1.20%
Below BBB-	Below Baa3	0.00%

2. Transmission Credit Limit for Unrated Non-Municipal Market Participant

The Transmission Credit Limit of each Unrated Non-Municipal Market Participant that satisfies the Credit Threshold shall at any time be equal to the lesser of: (i) 0.50 percent (0.50% or ½ of 1%) of such Unrated Non-Municipal Market Participant's Tangible Net Worth or (ii) $25 million. The Transmission Credit Limit of each Unrated Non-Municipal Market Participant that does not satisfy the Credit Threshold shall be $0.

3. Transmission Credit Limit for Municipal Market Participants

The Transmission Credit Limit for each Credit Qualifying Municipal Market Participant shall be equal to $25 million. The Transmission Credit Limit for each Non-Qualifying Municipal Market Participant shall be $0. The sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates or have provided a corporate guaranty from the same Guarantor, Canadian Guarantor or Foreign Guarantor shall not exceed $50 million.

F. Credit Limits for FTR-Only Customers

The Market Credit Limit and Transmission Credit Limit of each FTR-Only Customer shall be $0.

G. Total Credit Limit

The sum of a Rated Non-Municipal Market Participant's Market Credit Limit and Transmission Credit Limit shall not exceed $50 million and the sum of the Market Credit

Limits and Transmission Credit Limits of entities that are Affiliates or have provided a corporate guaranty from the same Guarantor, Canadian Guarantor or Foreign Guarantor shall not exceed $50 million. No later than five Business Days prior to the first day of each calendar quarter, and no later than five Business Days after any Affiliate change, each Rated Non-Municipal Market Participant that has a Market Credit Limit and a Transmission Credit Limit shall determine the amounts to be allocated to its Market Credit Limit (up to the limit set forth in Section II.D.1.a above) and its Transmission Credit Limit (up to the limit set forth in Section II.E.1 above) such that the sum of its Market Credit Limit and its Transmission Credit Limit are equal to not more than $50 million and such that the sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates or have provided a corporate guaranty from the same Guarantor, Canadian Guarantor or Foreign Guarantor do not exceed $50 million and shall provide the ISO with that determination in writing. Each Rated Non-Municipal Market Participant may provide such determination for up to four consecutive calendar quarters. If a Rated Non-Municipal Market Participant does not provide such determination, then the ISO shall use the amounts provided for the previous calendar quarter. If no such determination is provided, then the ISO shall apply an allocation of $25 million each to the Market Credit Limit and Transmission Credit Limit, which values shall also be used in allocating the $50 million credit limit among Affiliates. If the sum of the amounts for Affiliates or entities with same Guarantor. Canadian Guarantor or Foreign Guarantor is greater than $50 million, then the ISO shall reduce the amounts (proportionally to the amounts provided by each Affiliate or each entity with same Guarantor, Canadian Guarantor or Foreign Guarantor, or to the allocation applied by the ISO in the case of an Affiliate that provided no determination) such that the sum is no greater than $50 million.

H. Corporate Guaranty

1. Eligibility for Corporate Guaranty.

For any Market Participant that does not satisfy the requirements for a Market Credit Limit or Transmission Credit Limit greater than zero, but can provide a corporate guaranty meeting the requirements of this Section II.H from an entity that either satisfies the rating requirements for such a Market Credit Limit or Transmission Credit Limit or satisfies the Credit Threshold and that also satisfies the other requirements in this Section

II.H, then such Market Participant may utilize the rating or Credit Threshold and the Tangible Net Worth of that entity (such entity, either a "Guarantor", "Canadian Guarantor" or "Foreign Guarantor" as described in more detail below) in order to establish a Market Credit Limit and/or Transmission Credit Limit for such Market Participant.[2]

Notwithstanding any other provisions of this ISO New England Financial Assurance Policy to the contrary, the sum of the Market Credit Limit and Transmission Credit Limit of a Market Participant that uses a corporate guaranty to establish those credit limits shall not exceed at any time (x) the total aggregate limit on the amount guaranteed under that corporate guaranty minus (y) any payments previously made by the Guarantor, Canadian Guarantor or Foreign Guarantor under that corporate guaranty, which amount shall be allocated to the Market Credit Limit and Transmission Credit Limit as provided in Section II.G.

A corporate guaranty is considered a transfer of unsecured credit. If there is a material change in the Guarantor, Canadian Guarantor or Foreign Guarantor such that it no longer satisfies the requirements to provide a corporate guaranty or if the corporate guaranty comes within thirty (30) days of expiring without renewal or terminating, then the Market Participant, will be required to provide an acceptable form of financial assurance under Section X as a replacement.

Any breach of a corporate guaranty or the requirements of the ISO New England Financial Assurance Policy by the Guarantor, Canadian Guarantor or Foreign Guarantor shall be deemed a Financial Assurance Default by the Market Participant on whose behalf the corporate guaranty was provided. Such a Financial Assurance Default shall also occur if: (1) the corporate guaranty expires or terminates other than pursuant to the terms thereof (unless the Market Participant provides a form of financial assurance under Section X); (2) the Guarantor, Canadian Guarantor or Foreign Guarantor disaffirms, disclaims, repudiates, rejects or challenges the validity of all or any part of the corporate

[2] MMWEC is considering whether any technical changes are needed in order for it to provide guaranties for its member entities.

guaranty; or (3) the corporate guaranty or any material provision of the corporate guaranty ceases to be in full force and effect, other than pursuant to the terms thereof.

2. Requirements for Guarantors, Canadian Guarantors and Foreign Guarantors.

Guarantor

An entity that is organized under laws of a jurisdiction within the United States and that satisfies the requirements of this Section II.H (a "Guarantor") may provide a corporate guaranty for a Market Participant, provided that such Guarantor is an Affiliate of such Market Participant, except that if such Market Participant is a Municipal Market Participant and is a member of a cooperative, joint action agency or similar entity that is also a Market Participant, that cooperative, joint action agency or similar entity may provide a corporate guaranty for such Municipal Market Participant.

Canadian Guarantor

An entity that is organized under the laws of a jurisdiction within Canada that satisfies the requirements of this Section II.H (a "Canadian Guarantor") may provide a corporate guaranty for a Market Participant, so long as the following additional conditions are also satisfied:

(i) such Canadian Guarantor is an Affiliate of the Market Participant on whose behalf the corporate guaranty is provided;

(ii) such corporate guaranty is denominated in U.S. currency;

(iii) such corporate guaranty is written and executed solely in English, including any duplicate originals; and

(iv) such Canadian Guarantor provides the financial statements required under the ISO New England Financial Assurance Policy in English and in accordance with generally accepted accounting principles in the United States or Canada or international financial reporting standards, with clear representation of net worth, tangible assets and any other information that the ISO may require in order to determine the eligibility of the Canadian Guarantor to provide a corporate guaranty.

Foreign Guarantor

An entity that is organized under the laws of a jurisdiction outside the United States and Canada that satisfies the requirements of this Section II.H (a "Foreign Guarantor") may

provide a corporate guaranty for a Market Participant, so long as the following additional conditions are also satisfied:

(i) such Foreign Guarantor is an Affiliate of the Market Participant on whose behalf the corporate guaranty is provided;

(ii) such Foreign Guarantor is domiciled in a country with a minimum long-term sovereign rating of AA+/Aa1, with the following conditions:

(x) sovereign ratings must be available from at least two of S&P, Moody's and Fitch;

(y) each rating agency's sovereign rating for the domicile will be considered to be the lowest of: country ceiling, senior unsecured government debt, long-term foreign currency sovereign rating, long-term local currency rating, or other equivalent measure selected in the ISO's sole discretion; and

(z) where equivalent ratings are not issued by the credit rating agencies, the lowest such rating shall apply;

(iii) such Foreign Guarantor is domiciled in a country that recognizes and enforces the judgment of state and federal courts in the United States;

(iv) such Foreign Guarantor provides the financial statements required under the ISO New England Financial Assurance Policy in English and in accordance with generally accepted accounting principles in the United States or international financial reporting standards, with clear representation of net worth, tangible assets and any other information that the ISO may require in order to determine the eligibility of the Foreign Guarantor to provide a corporate guaranty;

(v) such Foreign Guarantor appoints an agent for the acceptance of service of process in the United States, which agent shall be situated in the Commonwealth of Massachusetts, absent legal constraint;

(vi) such Foreign Guarantor demonstrates financial commitment to activity in the United States as evidenced by either having American Depository Receipts (ADRs) traded on the New York Stock Exchange, American Stock Exchange or NASDAQ, or by having equity ownership over USD 100,000,000 in wholly owned or majority owned subsidiaries organized under the laws of a jurisdiction within the United States; and

(vii) such Foreign Guarantor provides the ISO with an opinion of legal counsel licensed to practice law in the United States and in the jurisdiction(s) in which

the Foreign Guarantor is organized and domiciled, in form and substance acceptable to the ISO in its sole discretion, confirming the enforceability of the corporate guaranty in such jurisdictions, the Foreign Guarantor's legal authorization to provide the corporate guaranty, the enforceability of the judgment of state and federal courts in the United States in the jurisdiction(s) of the Foreign Guarantor's organization and domicile, and such other matters as the ISO shall determine in its sole discretion.

3. **Form of Corporate Guaranty**. Attachment 7 provides a generally acceptable sample "clean" Guarantor's corporate guaranty, Attachment 8 provides a generally acceptable sample "clean" Canadian Guarantor's corporate guaranty, and Attachment 9 provides a generally acceptable sample "clean" Foreign Guarantor's corporate guaranty. All corporate guarantees shall be one of these forms (with only minor, non-material changes), unless a variation therefrom is approved by the ISO after consultation with the NEPOOL Budget and Finance Subcommittee and filed with the Commission.

III. MARKET PARTICIPANTS' REQUIREMENTS

Each Market Participant that provides the ISO with financial assurance pursuant to this Section III must provide the ISO with financial assurance in one of the forms described in Section X below and in an amount equal to the amount required in order to avoid suspension under Section III.B below (the "Market Participant Financial Assurance Requirement"). A Market Participant's Market Participant Financial Assurance Requirement shall remain in effect as provided herein until the later of (a) 120 days after termination of the Market Participant's membership or (b) the end date of all FTRs awarded to the Market Participant and the final satisfaction of all obligations of the Market Participant providing that financial assurance; provided, however that financial assurances required by the ISO New England Financial Assurance Policy related to potential billing adjustments chargeable to a terminated Market Participant shall remain in effect until such billing adjustment request is finally resolved in accordance with the provisions of the ISO New England Billing Policy. Furthermore and without limiting the generality of the foregoing, (i) any portion of any financial assurance provided under the ISO New England Financial Assurance Policy that relates to a Disputed Amount shall not be terminated or returned prior to the resolution of such dispute, even if the Market Participant providing such financial assurance is terminated or voluntarily terminates its MPSA and otherwise satisfies all of its obligations to the ISO and (ii) the ISO shall not return or permit the termination of any financial assurance provided under the ISO New England Financial Assurance Policy by a Market Participant that has terminated its membership or been

percent (90%). If such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage or Transmission Credit Test Percentage exceeds 90 percent (90%), the ISO shall issue a notice thereof to such Market Participant. If sufficient financial assurance to lower such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage to less than or equal to 90 percent (90%) is not provided by 8:30 a.m. Eastern Time on the next Business Day, then the consequences described in subsections (a), (b) and (c) of Section III.B.2.c (iii) above shall apply until such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage are at 90 percent (90%) or less.

However, when a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent (100%) or 90 percent (90%), as applicable under this Section III.B.2.c, solely because its Investment Grade Rating is downgraded by one grade and the resulting grade is BBB-/Baa3 or higher, then (x) for five Business Days after such downgrade, such downgrade shall not by itself cause a change to such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage and (y) no notice shall be sent and none of the other actions described in this Section III.B shall occur with respect to such downgrade if such Market Participant cures such default within such five Business Day period. When a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent solely because a letter of credit or a surety bond is valued at $0 prior to the termination of that letter of credit or surety bond, as described in Section X.B or Section X.C, respectively, then the ISO, in its sole discretion, may determine that: (x) for five (5) Business Days after such change in the valuation of ~~the~~such letter of credit or surety bond, such valuation shall not by itself cause a change to such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage; and/or (y) no notice shall be sent and none of the other actions described in this Section III.B shall occur with respect to such valuation if such Market Participant cures such default within such five (5) Business Day period.

Notwithstanding the foregoing, a Market Participant shall neither (x) receive a notice that its Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit

A+	A1	3.05%
A	A2	2.85%
A-	A3	2.60%
BBB+	Baa1	2.30%
BBB	Baa2	1.90%
BBB-	Baa3	1.20%
Below BBB-	Below Baa3	0.00%

The Transmission Credit Limit of each Unrated Non-Market Participant Transmission Customer that satisfies the NMPTC Credit Threshold shall at any time be equal to the lesser of: (i) 0.50 percent (0.50% or ½ of 1%) of such Unrated Non-Market Participant Transmission Customer's Tangible Net Worth or (ii) $25 million. The Transmission Credit Limit of each Unrated Non-Market Participant Transmission Customer that does not satisfy the NMPTC Credit Threshold shall be $0.

3. Corporate Guaranty.

For any Non-Market Participant Transmission Customer that does not satisfy the requirements for a Market Credit Limit or Transmission Credit Limit greater than zero, but can provide a corporate guaranty meeting the requirements of Section II.H from a Guarantor, Canadian Guarantor or Foreign Guarantor that either satisfies the rating requirements for such a Market Credit Limit or Transmission Credit Limit or satisfies the Credit Threshold and that also satisfies the other requirements in Section II.H, then such Non-Market Participant Transmission Customer may utilize the rating or Credit Threshold and the Tangible Net Worth of that Guarantor, Canadian Guarantor or Foreign Guarantor in order to establish a Market Credit Limit or Transmission Credit Limit for such Non- Market Participant.

~~3~~4. NMPTC Total Credit Limit

The sum of a Non-Market Participant Transmission Customer's Market Credit Limit and Transmission Credit Limit shall not exceed $50 million and the sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates or have provided a corporate guaranty from the same Guarantor, Canadian Guarantor or Foreign Guarantor shall not exceed $50 million. No later than five Business Days prior to the first day of each calendar quarter, and no later than five Business Days after any Affiliate change,

each Rated Non-Market Participant Transmission Customer that has a Market Credit Limit and a Transmission Credit Limit shall determine the amounts to be allocated to its Market Credit Limit (up to the amount set forth in Section V.B.1 above) and its Transmission Credit Limit (up to the amount set forth in Section V.B.2 above) such that the sum of its Market Credit Limit and its Transmission Credit Limit are equal to not more than $50 million and such that the sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates or have provided a corporate guaranty from the same Guarantor, Canadian Guarantor or Foreign Guarantor do not exceed $50 million and shall provide the ISO with that determination in writing. Each Rated Non-Market Participant Transmission Customer may provide such determination for up to four consecutive calendar quarters. If a Rated Non-Market Participant Transmission Customer does not provide such determination, then the ISO shall use the amounts provided for the previous calendar quarter. If no such determination is provided, then the ISO shall apply an allocation of $25 million each to the Market Credit Limit and Transmission Credit Limit, which values shall also be used in allocating the $50 million credit limit among Affiliates or entities with the same Guarantor, Canadian Guarantor or Foreign Guarantor. If the sum of the amounts for Affiliates or entities with the same Guarantor, Canadian Guarantor or Foreign Guarantor is greater than $50 million, then the ISO shall reduce the amounts (proportionally to the amounts provided by each Affiliate or each entity with the same Guarantor, Canadian Guarantor or Foreign Guarantor, or to the allocation applied by the ISO in the case of an Affiliate that provided no determination) such that the sum is no greater than $50 million.

C. Information Reporting Requirements for Non-Market Participant Transmission Customers

Each Rated Non-Market Participant Transmission Customer having a Market Credit Limit or Transmission Credit Limit greater than zero or meeting the capitalization requirements by maintaining a minimum Tangible Net Worth or minimum total assets as described in Section II.A.4(a) shall submit to the ISO, on a quarterly basis, within 10 days of their becoming available and within 65 days after the end of the applicable fiscal quarter of such Rated Non-Market Participant Transmission Customer, its balance sheet, which shall show sufficient detail for the ISO to assess the Rated Non-Market Participant Transmission Customer's Tangible Net Worth. In addition, each Rated Non-Market Participant Transmission Customer that has an Investment Grade Rating having a Market

d. Upon the completion of the substitution auction, the amount to be included in the calculation of the FCM Financial Assurance Requirements for a Designated FCM Participant as described in Section VII.F.1 above shall be adjusted to reflect all charges and credits related to the purchase or sale of Capacity Supply Obligations in the substitution auction.

VIII. [Reserved]

IX. THIRD-PARTY CREDIT PROTECTION

The ISO shall obtain third-party credit protection, in the form of credit insurance coverage, a performance or surety bond, or a combination thereof ("Credit Coverage"), on terms acceptable to the ISO in its reasonable discretion covering collectively the Credit Qualifying Rated Market Participants. The amount of the Credit Coverage shall be adjusted monthly and shall be equal to at least the sum of (x) 3.5 times the average Hourly Charges for all Credit Qualifying Market Participants within the previous fifty-two calendar weeks plus (y) 3.5 times the sum of the average Non-Hourly Charges and the average Transmission Charges for all Credit Qualifying Market Participants within the previous twelve calendar months. The Credit Coverage shall be provided by an insurance company rated "A-" or better by A.M. Best & Co. or "A" or better by S&P. The cost of the Credit Coverage obtained for each calendar year shall be allocated to all Credit Qualifying Market Participants pro rata based, for each Credit Qualifying Market Participant, on the average amount of the Invoices issued to that Credit Qualifying Market Participant under the ISO New England Billing Policy in the preceding calendar year. Each Credit Qualifying Market Participant shall provide the ISO with such information as may be reasonably necessary for the ISO to obtain the Credit Coverage at the lowest possible cost.

X. ACCEPTABLE FORMS OF FINANCIAL ASSURANCE

Provided that the requirements set forth herein are satisfied, acceptable forms of financial assurance include shares of registered or private mutual funds held in a shareholder account ~~or~~, a letter of credit, or a surety bond each in accordance with the provisions of this Section X. All costs associated with obtaining financial security and meeting the provisions of the ISO New England Financial Assurance Policy are the responsibility of the Market Participant or Non-Market Participant Transmission Customer providing that security (each a "Posting Entity"). Any Posting Entity requesting a change to one of the model forms attached to the ISO New England Financial Assurance Policy which would be specific to such Posting Entity (as opposed to a generic improvement to such form) shall, at the time of making that request, pay a $1,000 change fee, which fee shall be deposited into the Late Payment Account maintained under the ISO New England Billing Policy.

ISO will not be renewed. Any letter of credit provided for a new Posting Entity for the purpose of covering the Initial Market Participant Financial Assurance Requirement must have a minimum term of 120 days.

2. Form of Letter of Credit

Attachment 2 provides a generally acceptable sample "clean" letter of credit, and all letters of credit provided by Posting Entities shall be in this form (with only minor, non-material changes), unless a variation therefrom is approved by the ISO after consultation with the NEPOOL Budget and Finance Subcommittee and filed with the Commission. Any letter of credit provided for a new Posting Entity must have a minimum term of 120 days. All costs incurred by the ISO in collecting on a letter of credit provided under the ISO New England Financial Assurance Policy shall be paid, or reimbursed to the ISO, by the Posting Entity providing that letter of credit.

C. Surety Bonds

A surety bond provides an acceptable form of financial assurance to the ISO. The surety bond must be payable immediately upon demand without prior determination of the validity of the demand and must be guaranteed to remain in effect for a period of not less than one (1) year. For purposes of the ISO New England Financial Assurance Policy, the surety bond will be valued at $0 at the end of the Business Day that is fifty (50) days prior to the termination of such surety bond. If the surety bond amount is below the required level, the Posting Entity must immediately obtain a replacement surety bond or obtain a substitute surety bond. The principal on a surety bond must be either the Posting Entity whose obligations are secured by such surety bond or an Affiliate of that Posting Entity.

1. Requirements for Surety

Each surety issuing a surety bond that serves as additional financial assurance must meet the requirements of this Section X.C. Each such surety must be an U.S. Treasury-listed approved surety. The ISO will post the current list of U.S. Treasury certified sureties on its website, and update that list and posting no less frequently than quarterly. In addition, the surety must have a minimum rating of "A-/A3" by S&P, Moody's, Fitch and/or A.M. Best. These ratings are minimum ratings and therefore, if any applicable rating from the Rating Agencies (including, for purposes of this Section X.C.1., A.M. Best), falls below

the levels listed above, such surety will not be considered to have satisfied the requirements in this Section X.C. Further, no Posting Entity may provide a surety bond that has been issued by a surety that is an Affiliate of that Posting Entity. If a surety fails to satisfy any of the criteria set forth above, the applicable Posting Entity will have five (5) Business Days from the date on which the ISO provides notice of such failure to replace the surety bond with a surety bond from a surety satisfying those criteria or provide other financial assurance satisfying the requirements of the ISO New England Financial Assurance Policy. In the case of a surety that is removed from the list of U.S. Treasury certified sureties, the ISO may extend that cure period to twenty (20) Business Days in its sole discretion. The ISO must promptly advise the NEPOOL Budget and Finance Subcommittee of any extension of a cure period beyond five (5) Business Days under this provision. No surety may issue or confirm surety bonds under the ISO New England Financial Assurance Policy in an amount exceeding either: (i) $20 million in the aggregate for any single Posting Entity; or (ii) $100 million in aggregate for a group of Posting Entities that are Affiliates or (iii) $100 million in the aggregate for surety bonds from the same surety.

The following provisions shall apply when a surety fails to honor the terms of one or more surety bonds issued or confirmed by the surety in favor of the ISO: (i) if the surety fails to honor the terms of one surety bond in a rolling seven hundred and thirty (730) day period, then the ISO will issue a notice of such failure to the NEPOOL Budget and Finance Subcommittee, to all members and alternates of the Participants Committee, to the New England governors and utility regulatory agencies and to the billing and credit contracts for all Market Participants; (ii) if the surety fails to honor either the terms of one surety bond twice or the terms of two surety bonds in a rolling seven hundred and thirty (730) day period, then the surety will no longer be eligible to issue or confirm surety bonds in favor of the ISO and any surety bonds issued or confirmed by such surety in favor of the ISO will not be renewed. Any surety bond provided for a new Posting Entity for the purpose of covering the Initial Market Participant Financial Assurance Requirement must have a minimum term of one hundred and twenty (120) days.

2. Form of Surety Bond

Attachment 6 provides a generally acceptable sample “clean” surety bond, and all surety bonds provided by Posting Entities shall be in this form (with only minor, non-material

changes), unless a variation therefrom is approved by the ISO after consultation with the NEPOOL Budget and Finance Subcommittee and filed with the Commission. All costs incurred by the ISO in collecting on a surety bond provided under the ISO New England Financial Assurance Policy shall be paid, or reimbursed to the ISO, by the Posting Entity providing that surety bond.

~~C~~D.- Special Provisions for Provisional Members

Notwithstanding any other provision of the ISO New England Financial Assurance Policy to the contrary, due to the temporary nature of a Market Participant's status as a Provisional Member and the relatively small amounts due from Provisional Members, any Provisional Member required to provide additional financial assurance under the ISO New England Financial Assurance Policy may only satisfy the portion of that requirement attributable to Participant Expenses under the RNA by providing a cash deposit in accordance with Section X.A. Provisional Members will not have any other Non-Hourly Requirements under the ISO New England Financial Assurance Policy. If a Provisional Member uses a standing instruction to pay its Invoices pursuant to the ISO New England Billing Policy, in order to avoid a default and/or a Late Payment Charge, the total amount of the cash deposited by that Provisional Member should be equal to the sum of (x) the Provisional Member's Financial Assurance Requirement under the ISO New England Financial Assurance Policy that is attributable to Participant Expenses under the RNA and (y) the amount due from that Provisional Member on its next Invoice under that ISO New England Billing Policy (not including the amount of any Qualification Process Cost Reimbursement Deposit (including the annual true-up of that amount) due from such Provisional Member). Provisional Members are also required to satisfy all other provisions of the ISO New England Financial Assurance Policy, and any additional financial assurance required to be provided by a Provisional Member that is not attributable to Participant Expenses may be satisfied by providing a cash deposit ~~or~~, letter of credit, or surety bond in accordance with this Section X but shall not be satisfied through the provision of the cash deposit described in this Section X.~~C~~D. Without limiting or reducing in any way the requirements of the ISO New England Financial Assurance Policy that apply to a Provisional Member, the amount of the cash deposit initially provided by a Provisional Member that is attributable to Participant Expenses (including any amounts provided in connection with the standing instruction under the ISO New England Billing Policy described above) shall be at least $2,500, and each

Provisional Member will replenish that cash deposit to at least that $2,500 level on December 31 of each year.

XI. MISCELLANEOUS PROVISIONS

A. Obligation to Report Material Adverse Changes

Each Market Participant and each Non-Market Participant Transmission Customer is responsible for informing the ISO in writing within five (5) Business Days of any Material Adverse Change in its financial status. A "Material Adverse Change" in financial status includes, but is not limited to, the following: a downgrade of the Market Participant or Non-Market Participant Transmission Customer or any Guarantor, Canadian Guarantor or Foreign Guarantor providing a corporate guaranty on behalf of that Market Participant or Non-Market Participant Transmission Customer to below an Investment Grade Rating by any Rating Agency; being placed on credit watch with negative implication by any Rating Agency if the Market Participant or Non-Market Participant Transmission Customer does not have an Investment Grade Rating; a bankruptcy filing or other insolvency by the Market Participant or Non-Market Participant Transmission Customer or by any Guarantor, Canadian Guarantor or Foreign Guarantor providing a corporate guaranty on behalf of that Market Participant or Non-Market Participant Transmission Customer; a report of a significant quarterly loss or decline of earnings of the Market Participant or Non-Market Participant Transmission Customer or any Guarantor, Canadian Guarantor or Foreign Guarantor providing a corporate guaranty on behalf of that Market Participant or Non-Market Participant Transmission Customer; the resignation of key officer(s) of the Market Participant or Non-Market Participant Transmission Customer or any Guarantor, Canadian Guarantor or Foreign Guarantor providing a corporate guaranty on behalf of that Market Participant or Non-Market Participant Transmission Customer; the sanctioning of the Market Participant or Non-Market Participant Transmission Customer or any Guarantor, Canadian Guarantor or Foreign Guarantor providing a corporate guaranty on behalf of that Market Participant or Non-Market Participant Transmission Customer or any of its Principals imposed by the Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Commodity Futures Trading Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; the filing of a material lawsuit that could materially

adversely impact current or future financial results of the Market Participant or Non-Market Participant Transmission Customer or any Guarantor, Canadian Guarantor or Foreign Guarantor providing a corporate guaranty on behalf of that Market Participant or Non-Market Participant Transmission Customer; or a significant change in the Market Participant's or Non-Market Participant Transmission Customer's market capitalization or the market capitalization of any Guarantor, Canadian Guarantor or Foreign Guarantor providing a corporate guaranty on behalf of that Market Participant or Non-Market Participant Transmission Customer. A Market Participant's or Non-Market Participant Transmission Customer's failure to timely disclose a Material Adverse Change in its financial status may result in termination proceedings by the ISO. If the ISO determines that there is a Material Adverse Change in the financial condition of a Market Participant~~-~~ ~~or~~, Non-Market Participant Transmission Customer, Guarantor, Canadian Guarantor or Foreign Guarantor, then the ISO shall provide to ~~that~~the applicable Market Participant or Non-Market Participant Transmission Customer a signed written notice two Business Days before taking any of the actions described below. The notice shall explain the reasons for the ISO's determination of the Material Adverse Change. After providing notice, the ISO may take one or more of the following actions: (i) require that, within two Business Days of receipt of the notice of Material Adverse Change, the Market Participant or Non-Market Participant Transmission Customer provide one of the forms of financial assurance described in Section X of the ISO New England Financial Assurance Policy and/or an additional amount of financial assurance in one of the forms of financial assurance described in Section X of the ISO New England Financial Assurance Policy; (ii) require that the Market Participant or Non-Market Participant Transmission Customer cease one or more transactions in the New England Markets; or (iii) require that the Market Participant or Non-Market Participant Transmission Customer take other measures to restore the ISO's confidence in its ability to safely transact in the New England Markets. Any additional amount of financial assurance required as a result of a Material Adverse Change shall be sufficient, as reasonably determined by the ISO, to cover the Market Participant's or Non-Market Participant Transmission Customer's potential settled and unsettled liability or obligation, provided, however, that if the additional amount of financial assurance required as a result of a Material Adverse Change is equal to or greater than $25 million, then the Chief Financial Officer shall first consult, to the extent practicable, with the ISO's Chief Executive Officer, Chief Operating Officer, and General Counsel. If the Market Participant or Non-

ATTACHMENT 6

SAMPLE SURETY BOND

Surety Bond No. _____

KNOW ALL PERSONS BY THESE PRESENTS that we, [**full legal name of Non-Municipal Market Participant**], a [_____] organized under the laws of the State of [_____], as Principal ("Principal"), and [**full legal name of surety**], a [_____] organized under the laws of the State of [_____], as surety ("Surety"), are held and firmly bound unto ISO New England Inc., a Delaware nonprofit corporation, (the "ISO"), in the amount of [_____] dollars ($[_____]) in lawful money of the United States of America (the "Amount") well and truly to be paid to the ISO, and we bind ourselves, our permitted successors, and permitted assigns, jointly and severally, firmly by the terms set forth in this Surety Bond (the "Surety Bond" or "Bond").

WHEREAS, Principal seeks to participate in the markets administered by the ISO and/or to schedule transmission service in the ISO Control Area; and

WHEREAS, Principal must satisfy the financial assurance requirements established in the ISO's Transmission, Markets, and Services Tariff (the "ISO Tariff") to participate in the markets administered by the ISO or to schedule transmission service in the ISO Control Area; and;

WHEREAS, Surety has agreed, in exchange for compensation provided by Principal, to provide this Surety Bond on behalf of Principal in accordance with the financial assurance requirements under the ISO Tariff;

NOW THEREFORE, in consideration of the premises and mutual covenants contained in this Bond and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, Principal and Surety agrees as follows:

Section 1. Definitions. Each capitalized term used herein and not otherwise defined in this Bond shall have the meaning assigned to it in the ISO Tariff.

Section 2. The Bond.

2.01 The Bond. Surety hereby unconditionally, absolutely, and irrevocably guarantees to the ISO and its successors and assigns the full punctual payment and performance by the Principal of all of the Principal's payment obligations to the ISO under the ISO Tariff (including the ISO New England Financial Assurance Policy and the ISO New England Billing Policy) and to the NEPOOL Participants under the NEPOOL Agreement (collectively, the "Obligations" or "Obligation") in an aggregate amount that is not greater than the Amount of this Bond. As used in this Surety Bond, the term Obligations or Obligation means, collectively, the following:

(a) any and all indebtedness, liabilities and sums of money now or hereafter due and owing by Principal to the ISO pursuant to, or arising under, the ISO Tariff, including (without limitation) all scheduling, operating, planning, reliability and settlement policies, rules, guidelines and procedures established from time to time by the ISO;

(b) any and all indebtedness, liabilities and sums of money now or hereafter due and owing by Principal to the NEPOOL Participants pursuant to, or arising under, the NEPOOL Agreement;

(c)any and all interest and out-of-pocket expenses (including reasonable attorneys' fees) now or hereafter due and owing by Principal pursuant to the ISO Tariff or the NEPOOL Agreement, whether or not allowed under any Debtor Relief Law (defined below) (including all post-petition interest accruing after the commencement of any bankruptcy or insolvency proceeding by or against Principal, whether or not allowed in such proceeding), and all other amounts that would be part of the Obligations but for the operation of Debtor Relief Laws;

(d) all assessments and other amounts required to be paid by Principal to the ISO or the NEPOOL Participants in order to conduct business with the ISO and the NEPOOL Participants notwithstanding the continuing right of Principal to dispute, contest or pursue rights of setoff of such assessments and other amounts; and

(e) all reasonable costs, expenses and fees, including, without limitation, court costs and attorneys' fees, arising in connection with the collection of any or all amounts, indebtedness, obligations and liabilities of Principal to the ISO and the NEPOOL Participants described in clauses (a) through (d) above.

For purposes of this Bond, the term "Debtor Relief Laws" shall mean Title 11 of the United States Code, as now or hereafter in effect, or any other applicable law, domestic or foreign, as now or hereafter in effect, relating to bankruptcy, insolvency, liquidation, receivership, reorganization, arrangement or composition, extension or adjustment of debts, or other debtor relief, or similar laws affecting the rights of creditors.

2.02 Obligations Unconditional. This Bond is not conditioned upon the ISO first attempting to collect payment, resorting to any other means of security or collateral, or pursuing any other remedies it may have. The obligations of Surety hereunder are independent obligations of Principal, and the ISO may bring an action against Surety without bringing an action against Principal. The ISO may from time to time, without notice or demand, and without affecting Surety's liability hereunder, take and hold other security for Principal's obligations to the ISO and exchange, waive, release or apply such security as the ISO deems appropriate in its sole discretion. Surety's liability under this Bond is not conditioned upon the validity or enforceability of Principal's obligations to the ISO.

2.03 Payment. Surety is responsible for and shall pay to the ISO all or any portion of the Obligations, in an aggregate amount that is not greater than the Amount of this Bond, and shall make any and all required payments, on or before 5:00 p.m., local time in Holyoke, MA, on the first (1st) Business Day after receiving notice from the ISO that the Principal has failed to meet any of the Obligations.

A demand for payment by the ISO shall be presented to the Surety in the form of a Demand for Payment similar to that shown in **Exhibit A** to this Bond. No other documents and/or information whatsoever is required to effectuate payment on this Bond by Surety other than the Demand for Payment. The demand rights in this paragraph are in addition to any other rights under this Bond.

It is a condition of this Bond that Surety shall be a U.S. Treasury-listed approved surety and shall maintain a corporate debt rating not less than that required by the ISO Tariff as of the Date of Issuance (defined below) of this Bond.

The ISO may, but shall have no obligation to, make demand for payment under this Bond at any time coincident with or after the time for payment of all or part of the Obligations, and such demand(s) may be made from time to time with respect to the same or different items of the Obligations. Such demand(s) may be made, given and received in accordance with the notice provisions hereof; provided, however, the failure to make, give or receive any such demand (or any failure of any such demand to be made in accordance with the notice provisions hereof) shall not relieve, limit or discharge Surety in any respect of its Obligations under this Bond.

Funds may be demanded by the ISO under this Bond, from time to time, in one or more demands or draws, in amounts not exceeding in the aggregate the Amount specified above. Partial demands are permitted and shall reduce the Amount thereafter available for demand under this Bond.

All sums payable by Surety under this Bond shall be by wire transfer of immediately available funds, without offset, in lawful money of the United States of America, which shall at the time of payment be legal tender for the payment of public and private debts. All payments shall be remitted to the ISO's account as designated by written notice to Surety.

2.04 Reinstatement. The Obligations (including, without limitation, the Bond) of Surety under this Section 2 shall be automatically reinstated if and to the extent that, for any reason, any payment or performance by or on behalf of the Principal in respect of the Obligations is rescinded or must be otherwise restored by any holder of any of the Obligations, whether as a result of any bankruptcy, reorganization, receivership, insolvency or other proceeding under any Debtor Relief Laws, and Surety agrees that it will indemnify the ISO on demand for all reasonable costs and expenses (including, without limitation, attorneys' fees) incurred by the ISO in connection with such rescission or restoration, including, without limitation, any such costs and expenses incurred in defending against any claim alleging that such payment constituted a preference, fraudulent transfer or similar payment under any bankruptcy, insolvency or similar law.

2.05 Subrogation. Surety hereby agrees that until the payment and satisfaction in full of all Obligations, it shall not exercise any right or remedy arising by reason of any performance by it of its obligations in Section 2.01 of this Bond, whether by subrogation or otherwise, against the Principal or any other surety of any of the Obligations.

2.06 Remedies. Surety agrees that, as between Surety and the ISO, the Obligations may be declared to be forthwith due and payable for purposes of Section 2.01 of this Bond notwithstanding any stay, injunction or other prohibition preventing such declaration (or such Obligation from becoming automatically due and payable) as against the Principal and that, in the event of such declaration (or such Obligations being deemed to have become automatically due and payable), such Obligations (whether or not due and payable by the Principal) shall forthwith become due and payable by Surety for purposes of such Section 2.01.

2.07 Term, Surety Nonrenewal, and Termination. This Bond shall be effective upon the Date of Issuance. The term of this Bond shall be for a period of one (1) year, commencing on the Date of Issuance and expiring one (1) year later.

Notwithstanding the foregoing, this Bond shall be automatically renewed and extended without amendment for one (1) year from the expiration date hereof, or one (1) year from any future expiration date, unless at least sixty (60) days prior to the expiration date the Surety sends written notice to the ISO stating that Surety elects not to renew and extend this Bond. If Surety notifies the ISO in writing that Surety elects to terminate this Bond and Principal fails to provide an acceptable form of replacement security to the ISO at least fifty (50) days prior to the termination of this Bond, Surety shall, upon

demand, without any notice other than such demand, and without any further action by the ISO deliver cash collateral to the ISO not later than the next Business Day in the amount of the full remaining value of this Bond as security for Principal's Obligations. Cash collateral provided to the ISO by Surety and not applied by the ISO to satisfy unpaid Obligations shall be returned to Surety at such time as: (i) Principal provides adequate replacement security to the ISO as required under the ISO Tariff or (ii) Principal ceases to be an ISO customer and all amounts owed by Principal to the ISO are paid in full, including amounts owed as a result of true-ups or other corrections to previous settlements.

Notwithstanding the foregoing, the ISO shall have the immediate right, but not the obligation, to terminate this Bond upon written notice to Surety and Principal (a) if any of the representations and warranties of the Surety contained in Section 4 are no longer true and correct, or (b) upon the Surety's failure to promptly deliver any information requested pursuant to Section 5.

2.08 Surety Continuing Liability. If Surety elects not to renew this Bond or the ISO terminates this Bond, Surety agrees and acknowledges that it shall remain liable for any Obligations arising before the effective date of Surety's nonrenewal or the ISO's termination of this Bond. Surety agrees and acknowledges that this Bond applies to all Obligations arising or committed to prior to the effective date of Surety's nonrenewal or the ISO's termination.

Section 3. Acknowledgements, Waivers and Consents. In full recognition and in furtherance of the foregoing, the Surety agrees that:

3.01 ISO Actions. Without affecting the enforceability or effectiveness of this Bond in accordance with its terms and without affecting, limiting, reducing, discharging or terminating the liability of the Surety, or the rights, remedies, powers and privileges of the ISO under this Bond, the ISO may, at any time and from time to time and without notice or demand of any kind or nature whatsoever to Surety:

(a) amend, supplement, modify, extend, renew, waive, accelerate or otherwise change the time for payment or performance of, or the terms of, all or any part of the Principal's Obligations (including without limitation any increase or decrease in the rate or rates of interest);

(b) amend, supplement, modify, extend, renew, waive or otherwise change, or enter into or give, any agreement, security document, guarantee, approval, consent or other instrument relating to all or any part of the Principal's Obligations;

(c) accept or enter into new or additional agreements, security documents, guarantees (including without limitation letters of credit) or other instruments in addition to, in exchange for or relative to the Obligations or any document now or in the future evidencing or serving as collateral provided by the Principal in accordance with the ISO Tariff or the NEPOOL Agreement;

(d) accept or receive partial payments or performance on the defaulting Principal's Obligations (whether as a result of the exercise of any right, remedy, power or privilege or otherwise);

(e) accept, receive and hold any additional collateral for all or any part of the defaulting Principal's Obligations;

(f) release, reconvey, terminate, waive, abandon, allow to lapse or expire, fail to perfect, subordinate, exchange, substitute, transfer, foreclose upon or enforce any collateral, security documents or guarantees (including without limitation letters of credit) for or relative to all or any part of the defaulting Principal's Obligations;

(g) apply any collateral or the proceeds of any Principal-specific collateral or other collateral to all or any part of the defaulting Principal's Obligations in such manner and extent as the ISO may in its discretion determine;

(h) release any entity from any liability with respect to all or any part of the defaulting Principal's Obligations;

(i) settle, compromise, release, liquidate or enforce upon such terms and in such manner as the ISO may determine or as applicable law may dictate all or any part of the defaulting Principal's Obligations or any collateral on or guarantee of (including without limitation any letter of credit issued with respect to) all or any part of such Principal's Obligations;

(j) consent to the merger or consolidation of, the sale of substantial assets by, or other restructuring or termination of the corporate existence of the defaulting Principal; and

(k) enter into such other transactions or business dealings with the defaulting Principal (or any of its affiliates) or any other guarantor or surety of all or any part of such Principal's Obligations as the ISO may desire.

3.02 Waivers. The enforceability and effectiveness of this Bond and the liability of the Surety, and the rights, remedies, powers and privileges of the ISO, under this Bond shall not be affected, limited, reduced, discharged or terminated, and the Surety hereby expressly waives to the fullest extent permitted by law any defense now or in the future arising, by reason of:

(a) the illegality, invalidity or unenforceability of all or any part of the defaulting Principal's Obligations, the ISO Tariff, the NEPOOL Agreement, such Principal's Principal-specific collateral or any agreement, security document, guarantee or other instrument relative to all or any part of the defaulting Principal's Obligations;

(b) any disability or other defense (including, without limitation, the defense of force majeure, breach of contract, breach of warranty, and fraud) with respect to all or any part of the Principal's Obligations or any of their guarantors or other financial assurance providers;

(c) any defense due to the Surety's failure to review the activities of Principal or any changes in the ISO Tariff or the NEPOOL Agreement (it being acknowledged and agreed that Surety bears all responsibility for monitoring the activities of the Principal);

(d) the cessation, for any cause whatsoever, of the liability of the Principal or any guarantor or other financial assurance provider of all or any part of the Principal's Obligations (other than by reason of the full payment and performance of all Obligations of the Principal);

(e) any failure of the ISO to exhaust any cash collateral or other financial assurance for all or any part of the Obligations, to pursue or exhaust any right, remedy, power or privilege it may have against Principal, any other guarantor or other financial assurance provider (including without limitation any issuer of any letter of credit), or any other entity or to take any action whatsoever to mitigate or reduce the Surety's liability under this Bond;

(f) any failure of the ISO to comply with applicable laws in connection with the disposition of any cash collateral for all or any part of the defaulting Principal's Obligations;

(g) any act or omission of the ISO or any other entity that directly or indirectly results in or aids the discharge or release of all or any part of the defaulting Principal's Obligations or any financial assurance or guaranty (including without limitation any letter of credit) for all or any part of such Obligations by operation of law or otherwise;

(h) any law which provides that the obligation of a surety or guarantor must neither be larger in amount nor in other respects more burdensome that that of the principal or which reduces a surety's or guarantor's obligation in proportion to the principal's obligation;

(i) any and all rights to which Surety may be entitled by virtue of the laws of any state governing suretyship and guarantees;

(j) the possibility that the Obligations of the defaulting Principal to the ISO may at any time and from time to time exceed the aggregate liability of the Surety under this Bond;

(k) any counterclaim, set-off (including as permitted by 11 U.S.C. § 362) or other claim which the defaulting Principal has or alleges to have with respect to all or any part of its Obligations;

(l) any action or inaction of the ISO in any bankruptcy or other proceeding with respect to any entity, including Principal;

(m) the avoidance of any lien in favor of the ISO for any reason;

(n) any bankruptcy, insolvency, reorganization, arrangement, readjustment of debt, liquidation or dissolution proceeding commenced by or against any entity, including any discharge of, or bar or stay against collecting, all or any part of the defaulting Principal's Obligations (or any interest on all or any part of the defaulting Principal's Obligations) in or as a result of any such proceeding;

(o) Principal's breach of any obligation owed to Surety, whether by contract or otherwise, including, without limitation, Principal's failure to pay any premiums due to Surety;

(p) any action taken by the ISO that is authorized in this Bond or by any other provision of the ISO Tariff or the NEPOOL Agreement or any omission to take any such action;

(q) any other circumstance whatsoever that might otherwise constitute a legal or equitable discharge or defense of a surety or guarantor, including by reason of existing law and any future judicial decisions or legislation or of any provisions of the laws of any other jurisdiction; or

(r) any and all other demands and notices to Surety or Principal, and any and all other formalities of any kind, the omission of or delay in performance of which might but for the provisions of this section constitute legal or equitable grounds for relieving or discharging Surety in whole or in part from its irrevocable, absolute and continuing obligations hereunder.

3.03 Actions against Principal. In furtherance of the foregoing, Surety agrees that (i) it is not necessary for the ISO, in order to enforce Surety's payment Obligations hereunder, first to proceed against Principal or resort to any other collateral, security or other guarantors or obligors, if any, or pursue any other remedy available to the ISO or the NEPOOL Participants with respect to the Obligations, and (ii) the ISO Tariff, the NEPOOL Agreement and any collateral, security or obligations of any guarantors or obligors, if any, may be renewed, extended, amended, modified, supplemented, sold, released, surrendered, exchanged, settled, compromised, waived, subordinated or modified, in each case without consideration and on any terms or conditions, without notice to, or further assent from, Surety and without in any way affecting the Obligations of Surety under this Bond.

3.04 No Set-off or Counterclaims. The Surety expressly waives, for the benefit of the ISO, all rights to set-off amounts due by the ISO to the Principal, all counterclaims, and all promptness, diligence, presentment, protest, notice of protest, notice of dishonor, notice of nonpayment or nonperformance, notice of any default, demand of payment, notice of intent to accelerate, notice of acceleration, and all other notices of any kind or nature whatsoever with respect to the Principal's Obligations, and all notices of acceptance of this Bond or of the existence, creation, incurring or assumption of new or additional Obligations.

3.05 No Modification to Obligations. Nothing in this Bond will, or will be construed or applied to, modify the Principal's Obligations under the ISO Tariff or the NEPOOL Agreement.

3.06 Costs and Fees. Principal shall pay all costs and fees for this Bond. Principal's failure to pay any such costs and fees hall not be grounds for termination of this Bond. All rights of Surety to proceed against Principal in respect of payment hereunder, by subrogation or otherwise:

(a) are hereby subordinated and deferred to and until the full and final payment and discharge of the Obligations; and

(b) Surety may not exercise any rights it may acquire by way of subrogation under this Bond, by payment made hereunder or otherwise, until all of the Obligations then due and payable have been fully and finally paid.

Section 4. Representations and Warranties. Surety represents and warrants to the ISO that:

4.01 U.S Treasury Approval and Credit Rating. As of the Date of Issuance, and for so long as this Bond shall remain in effect, Surety has, and shall continue to satisfy and maintain, a minimum corporate credit rating of "A-" or "A3," as applicable, with S&P, Moody's, Fitch, or A.M. Best, or as

otherwise required under the ISO Tariff, and is, and will continue to be, a U.S. Treasury-listed approved surety. Surety shall notify the ISO immediately if its credit rating is decreased or if it is ceases to be a U.S. Treasury-listed approved surety.

4.02 Corporate Action. Surety has all necessary corporate power and authority to execute, deliver and perform its Obligations under this Bond; the execution, delivery and performance by Surety of this Bond has been duly authorized by all necessary corporate action on its part; the person executing this Bond on behalf of the Surety has full power and authority to bind the Surety to this Bond; and this Bond has been duly and validly executed and delivered by Surety and constitutes a legal, valid and binding obligation of Surety, enforceable in accordance with its terms.

4.03 Litigation. There are no legal or arbitral proceedings or any proceedings by or before any governmental or regulatory authority, or agency, now pending or (to the best knowledge of Surety) threatened against Surety or any of its subsidiaries that, if adversely determined, could (either individually or in the aggregate) have a material adverse effect on the consolidated financial condition, operations, business or prospects, taken as a whole, of Surety and its subsidiaries or the ability of Surety to perform its obligations under this Bond.

4.04 No Breach. Neither the execution and delivery of this Bond, nor consummation of the transactions contemplated in this Bond, nor compliance with the terms and provisions of this Bond, will conflict with, result in a breach of, or require any consent under, the charter or by-laws of Surety, any applicable law or regulation, any order, writ, injunction or decree of any court or governmental authority or agency, any agreement or instrument to which Surety or any of its subsidiaries is a party or by which any of them is bound or to which any of them is subject, or constitute a default under any such agreement or instrument, or result in the creation or imposition of any lien upon of the revenues or assets of Surety or any of its subsidiaries pursuant to the terms of any such agreement or instrument.

4.05 No Defaults. To the best of its knowledge Surety is not in default or breach under any agreements or contracts which may adversely affect Surety's ability to fulfill its Obligations under this Bond. Furthermore, Surety is not aware of any fact that would adversely affect Surety's ability to perform its Obligations under this Bond.

4.06 Independent Review. Surety has, independently and without reliance upon the ISO, and based upon such documents and information as Surety has deemed appropriate, made its own analysis and decision to enter into this Bond. Surety will keep itself fully apprised of Principal's financial and business condition, and Surety shall be solely responsible, to the extent deemed necessary or advisable by Surety, for obtaining for itself information regarding Principal, the ISO Tariff and the NEPOOL Agreement, and Surety acknowledges and agrees that the ISO shall have no duty at any time to notify Surety of any information which the ISO may have or acquire concerning Principal or to investigate or inform Surety of the financial or business condition or affairs of Principal or any change therein.

4.07 No Reliance on the ISO. NEITHER THE ISO NOR ANY AFFILIATE, EMPLOYEE, AGENT, OR REPRESENTATIVE OF THE ISO HAS MADE ANY REPRESENTATION, WARRANTY OR STATEMENT TO SURETY IN ORDER TO INDUCE SURETY TO EXECUTE THIS BOND, AND SURETY HEREBY EXPRESSLY WAIVES ANY CLAIM OF MISREPRESENTATION OR FRAUDULENT INDUCEMENT TO EXECUTE THIS BOND AND FURTHER DISCLAIMS ANY RELIANCE ON STATEMENTS OR REPRESENTATIONS OF THE ISO OR ANY AFFILIATE, EMPLOYEE, AGENT, OR REPRESENTATIVE OF THE ISO IN WAIVING SUCH A CLAIM.

Section 5. Miscellaneous.

5.01 No Waiver. No failure on the part of the ISO to exercise, and no course of dealing with respect to, and no delay in exercising, any right, power or remedy under this Bond shall operate as a waiver thereof, nor shall any single or partial exercise by the ISO of any right, power or remedy under this Bond preclude any other or further exercise thereof or the exercise of any other rights, power or remedy. The remedies in this Bond are cumulative and are not exclusive of any remedies provided by law.

5.02 Notices. Demands, notices, and other communications shall be deemed effective when received, shall be in writing, and shall be delivered by courier with receipt of delivery or by registered mail, certified mail, or facsimile to the following addresses:

Notice to the ISO: ISO New England Inc.
1 Sullivan Rd.
Holyoke, MA 01040
Attention: Credit Department
Fax: [_____]

Notice to Surety: [_____]
[_____]
[_____]
Attention: [_____]
Fax: [_____]

5.03 Costs and Expenses. Surety agrees to pay all of the ISO's costs and expenses (including, without limitation, reasonable attorneys' fees) which may be incurred in connection with the collection or enforcement of the Obligations or any part of them or any term of this Bond, including all such costs and expenses incurred by the ISO in any legal action, reference or dispute resolution proceeding. The recovery of such costs and expenses incurred by the ISO in connection with the enforcement of this Bond against Surety shall be in addition to Surety's Obligations under Section 2.01.

5.04 Amendments and Waivers. This Bond represents the entire agreement between Surety and the ISO and supersedes all prior agreements. The terms of this Bond may not be waived, altered or amended except in writing duly executed by Surety and the ISO. Any waiver or consent given shall be effective only in the specific instance and for the specific purpose for which it was given.

5.05 Successors and Assigns. This bond shall be binding upon and inure to the benefit of the respective successors and assigns of Surety, the ISO and each subsequent holder of any of the Obligations; provided, however, that Surety shall not be permitted to assign or transfer its rights and Obligations under this Bond without the prior written consent of the ISO. The ISO shall be permitted to assign its rights and remedies hereunder, in whole or in part, without the consent of Principal or Surety.

5.06 Governing Law and Venue. This Bond shall be governed by the laws of the Commonwealth of Massachusetts without regard to conflict of laws principles. Surety irrevocably submits to the jurisdiction of any Massachusetts court or any United States court sitting in Massachusetts over any action or proceeding arising out of or relating to this Bond and irrevocably agrees that all claims in such action or proceeding may be heard and determined by such court. Surety agrees that a final judgment in any such action or proceeding shall be conclusive and may be enforced in other jurisdictions

by suit on the judgment or in any other manner provided by law. Surety waives any objection to venue on the basis of forum non conveniens. Surety irrevocably consents to the service of process in any action or proceeding by the mailing of copies of such process to Surety at its address set forth herein. Nothing herein shall affect the right of the ISO to bring any action or proceeding against Surety or its property in the courts of any other jurisdictions.

5.07 Severability. Should any provision of this Bond be determined by a court of competent jurisdiction to be unenforceable, all other provisions shall remain effective.

5.08 Waiver of Jury Trial. SURETY IRREVOCABLY, VOLUNTARILY, AND WITH ADVICE OF COUNSEL WAIVES ANY RIGHTS IT MAY HAVE TO A TRIAL BY JURY IN ANY ACTION ARISING IN CONNECTION WITH THIS SURETY BOND.

Signed, sealed and dated this [___] day of [_____], 20[__] (the "Date of Issuance").

PRINCIPAL:

By: _____ (Seal)
Name: _____
Title: _____

SURETY:

By: _____ (Seal)
Name: _____
Title: _____

EXHIBIT A

(Form of Demand for Payment—Principal Failure to Make Payment)

[**Date**][1]

[**Name and Address of Surety**][2]

Re: Surety Bond No. _____
Demand for Payment

To the above named Surety:

The undersigned hereby certifies to [**full legal name of surety**] ("Surety"),with reference to its Surety Bond No. [**bond number**], dated [**execution date of Surety Bond**], issued on behalf of [**full legal name of customer**] ("Principal") and in favor of ISO New England Inc. (the "ISO") that Principal has failed to make payment in accordance with the terms of the ISO Tariff, the NEPOOL Agreement or any other related agreement between the ISO or the NEPOOL Participants and Principal. The ISO hereby demands payment in the amount of $ [**amount**] in accordance with the following instructions.

[**wiring instructions**]

ISO New England Inc.

By: _____[3]

Name: _____

Title: _____

[1] The date of the Demand for Payment Notice must be the date for which presentation of the Notice is made.
[2] This will be the address of the Surety as set forth in the Surety Bond.
[3] The undersigned must be an officer or authorized agent of the ISO.

EXHIBIT B

(Form of Demand for Payment – Surety Failure to Maintain Treasury Approval and Credit Rating)

[**Date**][4]

[**Name and Address of Surety**][5]

Re: Surety Bond No. _____
Demand for Payment

To the above named Surety:

The undersigned hereby certifies to [**full legal name of surety**] ("Surety"),with reference to its Surety Bond No. [**bond number**], dated [**execution date of Surety Bond**], issued on behalf of [**full legal name of ISO customer**] ("Principal") and in favor of ISO New England Inc. (the "ISO") that as of the close of business on [**date**],[6] Surety [is not a U.S. Treasury-listed approved surety] [has not maintained the rating] as required by the ISO Tariff, and Principal has failed to replace this Surety Bond in satisfaction of the credit requirements established pursuant to the ISO Tariff. The ISO hereby demands payment in the amount of $ [**amount**] in accordance with the following instructions.

[**wiring instructions**]

ISO New England Inc.

By: _____[7]

Name: _____

Title: _____

[4] The date of the Demand for Payment Notice must be the date for which presentation of the Notice is made.
[5] This will be the address of the Surety as set forth in the Surety Bond.
[6] Insert date less than fifty (50) days prior to expiration of the Surety Bond.
[7] The undersigned must be an officer or authorized agent of the ISO.

ATTACHMENT 7

SAMPLE CORPORATE GUARANTY
(U.S. GUARANTOR)

This GUARANTY AGREEMENT, dated [_____], ("Guaranty") is made by **[full legal name of guarantor]**, a **[state of formation and legal form of Guarantor]** ("Guarantor") on behalf of **[full legal name of Market Participant/Non-Market Participant Transmission Customer]**, a **[state of formation and legal form of Customer]** ("Customer"), and in favor of ISO New England Inc. (the "ISO"), a Delaware nonprofit corporation. Capitalized terms used herein shall have the meaning specified in Section I of the ISO New England Transmission, Markets, and Services Tariff (the "ISO Tariff").

WHEREAS, Customer seeks [to participate in the markets administered by the ISO and purchase other services in the ISO Control Area] [to obtain transmission service in the ISO Control Area]; and

WHEREAS, Customer seeks [to establish a "Market Credit Limit" and a "Transmission Credit Limit" under the ISO New England Financial Assurance Policy (the "Financial Assurance Policy")] [to satisfy the capitalization requirements under the ISO New England Financial Assurance Policy (the "Financial Assurance Policy")] through the provision of a corporate guaranty;

WHEREAS, **[description of Guarantor's legal affiliation with Customer]**; and

WHEREAS, Customer's [participation in the ISO markets] [receipt of transmission service in the ISO Control Area] will directly or indirectly benefit Guarantor;

NOW, THEREFORE, in consideration of the foregoing and the benefits to Guarantor arising from its relationship with Customer, Guarantor hereby agrees and covenants as follows:

1. Guaranteed Amounts. Guarantor unconditionally and irrevocably guarantees the prompt and complete payment of all amounts that Customer now or hereafter owes pursuant to the ISO Tariff, the Financial Assurance Policy, the ISO New England Billing Policy, the NEPOOL Agreement, the Participants Agreement and any other agreements, whether now existing or hereafter arising, between Customer and either the ISO or the NEPOOL Participants, as those tariffs, policies and agreements may be amended from time to time (collectively referred to as "the Agreements"); provided, however, that the aggregate amount guaranteed by Guarantor under this Guaranty shall not exceed $[_____].

2. Term of Guaranty. This Guaranty shall continue in full force and effect until the earlier of (a) the date on which the Agreements are terminated with respect to Customer and all amounts owed by Customer pursuant to the Agreements are paid in full, including any amounts owed as a result of true-ups or other corrections to settlements of obligations owed or incurred while the Agreements and this Guaranty are in effect and (b) **[date]**. This Guaranty may be enforced by the ISO from time to time and as often as occasion for such enforcement may arise prior to the expiration or termination hereof. Guarantor's liability hereunder shall survive the expiration or termination hereof and remain in full force and effect as to obligations owed or incurred by

Customer during the term of this Guaranty. This Guaranty shall survive and continue to bind Guarantor following any merger, reorganization, consolidation, or other change in Customer's or Guarantor's structure or business affairs.

3. Termination of Guaranty. Guarantor may terminate this Guaranty upon sixty (60) days written notice to the ISO.

4. Guaranty of Payment. This is a guaranty of payment and not of collection. If Customer fails to make any payment when due in strict accordance with the Agreements, Guarantor, upon demand, without any notice other than such demand, and without any further action by the ISO, shall make such payment not later than 5:00 p.m. (eastern prevailing time) on the next business day after such demand is made.

5. Obligations Unconditional. This Guaranty is a primary, absolute, unconditional, and continuing guaranty of the full and punctual payment by Customer of its obligations under the Agreements. Guarantor unconditionally guarantees the prompt and complete payment of all amounts owed by Customer under the Agreements if all or any part of such amounts is not paid by Customer when due. The ISO may from time to time, without notice or demand, and without affecting Guarantor's liability hereunder: (i) renew, extend, or otherwise change the terms of the Agreements and (ii) take and hold other security or financial assurance for this Guaranty or the Agreements and exchange, waive, release, or apply such security or financial assurance as the ISO deems appropriate in its sole discretion. Guarantor's liability under this Guaranty is not conditioned upon the validity or enforceability of the Agreements. Guarantor irrecoverably waives presentment, diligence, demand, protest or other notice of any kind, including, without limitation, notice of acceptance of this Guaranty and notice of any claim or demand upon Customer or Guarantor, it being understood that Guarantor waives all suretyship defenses generally.

6. Additional Security. This Guaranty shall be in addition to, and not in substitution for or degradation of, any other security or financial assurance that the ISO may at any time hold in respect of the obligations of Customer under the Agreements. The ISO may enforce this Guaranty notwithstanding that it may hold any guarantee, lien, security of or for Customer under the Agreements, or have available to it any other remedy at law or equity.

7. Expenses. Guarantor shall pay on demand all reasonable costs incurred by the ISO in the enforcement of this Guaranty, including attorney fees and expenses.

8. ISO Remedies; No Set-Off. The rights and remedies of the ISO under this Guaranty are cumulative and concurrent and shall not be exclusive of any other rights or remedies that the ISO may have against Customer or Guarantor. No set-off, counterclaim, or defense of any kind that Guarantor may have against Customer or any other guarantor shall diminish or impair the rights and remedies of the ISO and the obligations of Guarantor hereunder.

9. Bankruptcy. In the event that, pursuant to any insolvency, bankruptcy, reorganization, receivership, or other debtor relief law or any judgment, order, or decision thereunder, the ISO must rescind or surrender any payment received by the ISO, any prior release or discharge from the terms of this Guaranty shall be nullified and this Guaranty shall be reinstated and remain in

full force and effect. Guarantor shall not prove any claim in competition with the ISO or the NEPOOL Participants regarding any payment under the Agreements in bankruptcy or insolvency proceedings of any nature.

10. Subordination. All indebtedness of Customer to Guarantor is subordinated to indebtedness of Customer to the ISO and the NEPOOL Participants, in each case whether now existing or hereafter arising. So long as there is no default under the Agreements, however, Guarantor may continue to receive and retain payments on the subordinated indebtedness.

11. Subrogation. Guarantor irrevocably waives any right of subrogation to any of the rights, claims, security interests, or liens of the ISO against Customer under the Agreements or in any collateral or other security, and Guarantor shall have no right of recourse, reimbursement, contribution, indemnification, or similar right against Customer or any other guarantor of Customer's payments under the Agreements until all amounts owed by Customer pursuant to the Agreements have been paid in full, including any amounts owed as a result of true-ups or other corrections to settlements of obligations incurred while this Guaranty is in effect. If any amount shall be paid to Guarantor on account of such subrogation rights at any time while any amount is due from Customer under the Agreements, such amount shall be held by Guarantor in trust for the ISO and shall, forthwith upon receipt by Guarantor, be turned over to the ISO in the exact form received by Guarantor (duly indorsed by Guarantor or Customer, if required), to be applied to Customer's obligations under the Agreements.

12. Financial Reporting. Guarantor shall be required to comply with the reporting requirements established in the Financial Assurance Policy for Guarantors.

13. Representations and Warranties. Guarantor represents and warrants to the ISO that:

a. Guarantor is duly organized, validly existing, and in good standing under the laws of **[state]**. Guarantor has the legal power to execute and deliver this Guaranty and to perform this Guaranty in accordance with its terms. All necessary actions have been taken to authorize the execution and delivery of this Guaranty and performance of this Guaranty in accordance with its terms. This Guaranty is a legal, valid, and binding obligation of Guarantor and is enforceable against Guarantor in accordance with its terms.

b. There is no action or proceeding pending or, to Guarantor's knowledge, threatened before any court, arbitrator, or governmental agency that may materially adversely affect Guarantor's ability to perform its obligations under this Guaranty.

c. The financial statements and all other written statements provided by Guarantor to the ISO in connection with this Guaranty and the Agreements are true and accurate in all material respects and do not omit any material fact that, without such fact, would make any part of those statements or this Guaranty misleading. There is no fact that Guarantor has not disclosed in writing to the ISO of which Guarantor is aware or which Guarantor can reasonably foresee that would materially adversely affect Guarantor or the ability of Guarantor to perform its obligations hereunder. At such reasonable times as the ISO requests, Guarantor will furnish the ISO with such other financial information as the ISO may reasonably request.

d. No bankruptcy or insolvency proceedings are pending or, to the best of Guarantor's knowledge, contemplated by or against Guarantor under Title 11 of the United States Code, as now or hereafter in effect, or any other applicable law, domestic or foreign, as now or hereafter in effect, relating to bankruptcy, insolvency, liquidation, receivership, reorganization, arrangement or composition, extension or adjustment of debts, or other debtor relief, or similar laws affecting the rights of creditors.

14. Assignment. The ISO may assign its rights under this Guaranty without in any way diminishing Guarantor's liability hereunder.

15. Adequacy of Consideration. Guarantor acknowledges that the consideration it has received on account of this Guaranty constitutes adequate consideration for its obligations hereunder. Guarantor acknowledges that the ISO will rely on this Guaranty in allowing Customer to undertake obligations under the Agreements. Guarantor waives any defense to the enforcement of this Guaranty based upon lack of consideration.

16. Communications.

a. Demands, notices, and other communications given to Guarantor shall be deemed effective when received, shall be in writing, and shall be delivered by hand with receipt of delivery or registered mail to the following address: **[Guarantor notice address.]**

b. Notices and other communications given to the ISO shall be deemed effective when received, shall be in writing, and shall be delivered by hand with receipt of delivery or registered mail to the following address:

ISO New England Inc.
Attention: Credit Department
1 Sullivan Rd.
Holyoke, Ma 01040

17. Amendment and Waiver. The terms and provisions of this Guaranty may not be amended or waived without the prior written consent of the ISO and Guarantor.

18. Entire Agreement. This Guaranty embodies the entire agreement between Guarantor and the ISO with respect to the matters set forth herein and supersedes all prior such agreements.

19. Severability. Should any provision of this Guaranty be determined by a court of competent jurisdiction to be unenforceable, all of the other provisions shall remain effective.

20. Choice of Law; Jurisdiction; Venue; and Service of Process. This Guaranty shall be governed by the laws of the Commonwealth of Massachusetts without regard to conflicts of laws principles. Guarantor irrevocably submits to the jurisdiction of any Massachusetts court or any United States court sitting in Massachusetts over any action or proceeding arising out of or relating to this Guaranty and irrevocably agrees that all claims in such action or proceeding may be heard and determined by such court. Guarantor agrees that a final judgment in any such action or proceeding shall be conclusive and may be enforced in other jurisdictions by suit on the judgment or in any other manner provided by law. Guarantor waives any objection to venue on

the basis of forum non conveniens. Guarantor irrevocably consents to the service of process in any action or proceeding by the mailing of copies of such process to Guarantor at its address set forth herein. Guarantor agrees that any action or proceeding brought against the ISO arising out of or relating to this Guaranty shall be brought only in a Massachusetts court or a United States court sitting in Massachusetts. Nothing herein shall affect the right of the ISO to bring any action or proceeding against Guarantor or its property in the courts of any other jurisdictions.

21. Waiver of Jury Trial. GUARANTOR IRREVOCABLY, VOLUNTARILY, AND WITH ADVICE OF COUNSEL WAIVES ANY RIGHTS IT MAY HAVE TO A TRIAL BY JURY IN ANY ACTION ARISING IN CONNECTION WITH THIS GUARANTY OR THE AGREEMENTS.

22. Dispute. Any dispute arising under, out of, in connection with, or relating to this Guaranty, including any dispute or difference concerning the existence, validity, or enforceability of this Guaranty shall be resolved in accordance with the dispute resolution procedures under the ISO Tariff.

IN WITNESS WHEREOF, the undersigned Guarantor has executed this Guaranty as of this _____ day of _____, _____.

[GUARANTOR]

By: _____

Name: _____

Title: _____

ATTACHMENT 8

SAMPLE CORPORATE GUARANTY
(CANADIAN GUARANTOR)

This CANADIAN GUARANTY AGREEMENT, dated [_____], ("Guaranty") is made by **[full legal name of guarantor]**, a **[province of formation and legal form of Guarantor]** ("Guarantor") on behalf of **[full legal name of Market Participant/Non-Market Participant Transmission Customer]**, a **[state of formation and legal form of Customer]** ("Customer"), and in favor of ISO New England Inc. (the "ISO"), a Delaware nonprofit corporation. Capitalized terms used herein shall have the meaning specified in Section I of the ISO New England Transmission, Markets, and Services Tariff (the "ISO Tariff").

WHEREAS, Customer seeks [to participate in the markets administered by the ISO and purchase other services in the ISO Control Area] [to obtain transmission service in the ISO Control Area]; and

WHEREAS, Customer seeks [to establish a "Market Credit Limit" and a "Transmission Credit Limit" under the ISO New England Financial Assurance Policy (the "Financial Assurance Policy")] [to satisfy the capitalization requirements under the ISO New England Financial Assurance Policy (the "Financial Assurance Policy")] through the provision of a corporate guaranty;

WHEREAS, **[description of Guarantor's legal affiliation with Customer]**; and

WHEREAS, Customer's [participation in the ISO markets] [receipt of transmission service in the ISO Control Area] will directly or indirectly benefit Guarantor.

NOW, THEREFORE, in consideration of the foregoing and the benefits to Guarantor arising from its relationship with Customer, Guarantor hereby agrees and covenants as follows:

1. Guaranteed Amounts. Guarantor unconditionally and irrevocably guarantees the prompt and complete payment of all amounts that Customer now or hereafter owes pursuant to the ISO Tariff, the Financial Assurance Policy, the ISO New England Billing Policy, the NEPOOL Agreement, the Participants Agreement and any other agreements, whether now existing or hereafter arising, between Customer and either the ISO or the NEPOOL Participants, as those tariffs, policies and agreements may be amended from time to time (collectively referred to as "the Agreements"); provided, however, that the aggregate amount guaranteed by Guarantor under this Guaranty shall not exceed $[_____].

2. Term of Guaranty. This Guaranty shall continue in full force and effect until the earlier of (a) the date on which the Agreements are terminated with respect to Customer and all amounts owed by Customer pursuant to the Agreements are paid in full, including any amounts owed as a result of true-ups or other corrections to settlements of obligations owed or incurred while the Agreements and this Guaranty are in effect and (b) **[date]**. This Guaranty may be enforced by the ISO from time to time and as often as occasion for such enforcement may arise prior to the expiration or termination hereof. Guarantor's liability hereunder shall survive the expiration or termination hereof and remain in full force and effect as to obligations owed or incurred by

Customer during the term of this Guaranty. This Guaranty shall survive and continue to bind Guarantor following any merger, reorganization, consolidation, or other change in Customer's or Guarantor's structure or business affairs.

3. Termination of Guaranty. Guarantor may terminate this Guaranty upon sixty (60) days written notice to the ISO.

4. Guaranty of Payment. This is a guaranty of payment and not of collection. If Customer fails to make any payment when due in strict accordance with the Agreements, Guarantor, upon demand, without any notice other than such demand, and without any further action by the ISO, shall make such payment not later than 5:00 p.m. (eastern prevailing time) on the next business day after such demand is made.

5. Obligations Unconditional. This Guaranty is a primary, absolute, unconditional, and continuing guaranty of the full and punctual payment by Customer of its obligations under the Agreements. Guarantor unconditionally guarantees the prompt and complete payment of all amounts owed by Customer under the Agreements if all or any part of such amounts is not paid by Customer when due. The ISO may from time to time, without notice or demand, and without affecting Guarantor's liability hereunder: (i) renew, extend, or otherwise change the terms of the Agreements and (ii) take and hold other security or financial assurance for this Guaranty or the Agreements and exchange, waive, release, or apply such security or financial assurance as the ISO deems appropriate in its sole discretion. Guarantor's liability under this Guaranty is not conditioned upon the validity or enforceability of the Agreements. Guarantor irrecoverably waives presentment, diligence, demand, protest or other notice of any kind, including, without limitation, notice of acceptance of this Guaranty and notice of any claim or demand upon Customer or Guarantor, it being understood that Guarantor waives all suretyship defenses generally.

6. Additional Security. This Guaranty shall be in addition to, and not in substitution for or degradation of, any other security or financial assurance that the ISO may at any time hold in respect of the obligations of Customer under the Agreements. The ISO may enforce this Guaranty notwithstanding that it may hold any guarantee, lien, security of or for Customer under the Agreements, or have available to it any other remedy at law or equity.

7. Expenses. Guarantor shall pay on demand all reasonable costs incurred by the ISO in the enforcement of this Guaranty, including attorney fees and expenses.

8. ISO Remedies; No Set-Off. The rights and remedies of the ISO under this Guaranty are cumulative and concurrent and shall not be exclusive of any other rights or remedies that the ISO may have against Customer or Guarantor. No set-off, counterclaim, or defense of any kind that Guarantor may have against Customer or any other guarantor shall diminish or impair the rights and remedies of the ISO and the obligations of Guarantor hereunder.

9. Bankruptcy. In the event that, pursuant to any insolvency, bankruptcy, reorganization, receivership, or other debtor relief law or any judgment, order, or decision thereunder, the ISO must rescind or surrender any payment received by the ISO, any prior release or discharge from the terms of this Guaranty shall be nullified and this Guaranty shall be reinstated and remain in

full force and effect. Guarantor shall not prove any claim in competition with the ISO or the NEPOOL Participants regarding any payment under the Agreements in bankruptcy or insolvency proceedings of any nature.

10. Subordination. All indebtedness of Customer to Guarantor is subordinated to indebtedness of Customer to the ISO and the NEPOOL Participants, in each case whether now existing or hereafter arising. So long as there is no default under the Agreements, however, Guarantor may continue to receive and retain payments on the subordinated indebtedness.

11. Subrogation. Guarantor irrevocably waives any right of subrogation to any of the rights, claims, security interests, or liens of the ISO against Customer under the Agreements or in any collateral or other security, and Guarantor shall have no right of recourse, reimbursement, contribution, indemnification, or similar right against Customer or any other guarantor of Customer's payments under the Agreements until all amounts owed by Customer pursuant to the Agreements have been paid in full, including any amounts owed as a result of true-ups or other corrections to settlements of obligations incurred while this Guaranty is in effect. If any amount shall be paid to Guarantor on account of such subrogation rights at any time while any amount is due from Customer under the Agreements, such amount shall be held by Guarantor in trust for the ISO and shall, forthwith upon receipt by Guarantor, be turned over to the ISO in the exact form received by Guarantor (duly indorsed by Guarantor or Customer, if required), to be applied to Customer's obligations under the Agreements.

12. Financial Reporting. Guarantor shall be required to comply with the reporting and other requirements established in the Financial Assurance Policy for Canadian Guarantors. All financial reports and other information submitted to the ISO shall be in the English language.

13. Payments.

a. All payments to the ISO by Guarantor shall made in U.S. dollars to such account in the United States as the ISO may from time to time designate to Guarantor and shall be free and clear of, and without deduction or withholding for or on account of, any present or future income, stamp or other taxes or levies, imposts, duties, charges, fees, deductions or withholdings now or hereafter imposed, levied, collected, withheld or assessed by any governmental authority (collectively, "Taxes"). If any Taxes are required to be withheld from any amounts payable to Guarantor under this Guaranty, the amounts payable shall be increased to the extent necessary to provide the full amount (after payment of all Taxes) owing by Guarantor under this Guarantee.

b. All references in the Agreements and in this Guaranty to sums denominated in dollars or with the symbol "$" refer to the lawful currency of the United States of America.

c. The obligations of Guarantor under this Guaranty shall, notwithstanding judgment in a currency other than U.S. dollars (the "Judgment Currency"), be discharged only to the extent that, on any day following receipt by the ISO of any sum adjudged to be due in the Judgment Currency, the ISO may in accordance with normal banking procedures purchase U.S. dollars with the Judgment Currency. If the amount of U.S. dollars so purchased is less than the sum originally due to the ISO in U.S. dollars, Guarantor agrees, as a separate obligation and notwithstanding such judgment, to indemnify the ISO against such loss.

14. Representations and Warranties. Guarantor represents and warrants to the ISO that:

a. Guarantor is duly organized, validly existing, and in good standing under the laws of the province of its organization. Guarantor has the legal power to execute and deliver this Guaranty and to perform this Guaranty in accordance with its terms. All necessary actions have been taken to authorize the execution and delivery of this Guaranty and performance of this Guaranty in accordance with its terms. This Guaranty is a legal, valid, and binding obligation of Guarantor and is enforceable against Guarantor in accordance with its terms.

b. There is no action or proceeding pending or, to Guarantor's knowledge, threatened before any court, tribunal, arbitrator, or governmental agency that may materially adversely affect Guarantor's ability to perform its obligations under this Guaranty.

c. The financial statements and all other written statements provided by Guarantor to the ISO in connection with this Guaranty and the Agreements are true and accurate in all material respects and do not omit any material fact that, without such fact, would make any part of those statements or this Guaranty misleading. There is no fact that Guarantor has not disclosed in writing to the ISO of which Guarantor is aware or which Guarantor can reasonably foresee that would materially adversely affect Guarantor or the ability of Guarantor to perform its obligations hereunder. At such reasonable times as the ISO requests, Guarantor will furnish the ISO with such other financial information as the ISO may reasonably request.

d. No bankruptcy or insolvency proceedings are pending or, to the best of Guarantor's knowledge, contemplated by or against Guarantor under Title 11 of the United States Code, as now or hereafter in effect, or any other applicable law, domestic or foreign, as now or hereafter in effect, relating to bankruptcy, insolvency, liquidation, receivership, reorganization, arrangement or composition, extension or adjustment of debts, or other debtor relief, or similar laws affecting the rights of creditors.

e. Guarantor is subject to Massachusetts civil and commercial law with respect to its obligations under this Guaranty and has no immunity, sovereign or otherwise, from any suit or proceeding, the jurisdiction of any court, recoupment, setoff, or legal process (and hereby waives any defense of immunity to the extent available to Guarantor). This Guaranty is in proper legal form for enforcement against Guarantor. No filing, recording or notarization of any kind is required for enforcement of this Guaranty. No tax or other charge not already paid must be paid on or as a condition to the enforceability of this Guaranty, and there are no taxes imposed by the country in which Guarantor is organized or has its principal business office on or by virtue of Guarantor's execution or delivery of this Guaranty other than payable by Guarantor and which have already been paid.

15. Assignment. The ISO may assign its rights under this Guaranty without in any way diminishing Guarantor's liability hereunder.

16. Adequacy of Consideration. Guarantor acknowledges that the consideration it has received on account of this Guaranty constitutes adequate consideration for its obligations hereunder. Guarantor acknowledges that the ISO will rely on this Guaranty in allowing

Customer to undertake obligations under the Agreements. Guarantor irrevocably waives any defense to the enforcement of this Guaranty based upon lack of consideration.

17. Communications and Service of Process.

a. Demands, notices, and other communications given to Guarantor shall be deemed effective when received, shall be in writing, and shall be delivered by hand with receipt of delivery or registered mail to the following address: **[Guarantor notice address.]**

b. Notices and other communications given to the ISO shall be deemed effective when received, shall be in writing, and shall be delivered by hand with receipt of delivery or registered mail to the following address:

ISO New England Inc.
Attention: Credit Department
1 Sullivan Rd.
Holyoke, Ma 01040

18. Amendment and Waiver. The terms and provisions of this Guaranty may not be amended or waived without the prior written consent of the ISO and Guarantor.

19. Entire Agreement. This Guaranty embodies the entire agreement between Guarantor and the ISO with respect to the matters set forth herein and supersedes all prior such agreements.

20. Severability. Should any provision of this Guaranty be determined by a court of competent jurisdiction to be unenforceable, all of the other provisions shall remain effective.

21. Choice of Law; Jurisdiction; Venue; and Service of Process. This Guaranty shall be governed by the laws of the Commonwealth of Massachusetts without regard to conflicts of laws principles. Guarantor irrevocably and unconditionally submits to the jurisdiction of any Massachusetts court or any United States court sitting in Massachusetts over any action or proceeding arising out of or relating to this Guaranty and irrevocably agrees that all claims in such action or proceeding may be heard and determined by such court. Guarantor agrees that a final judgment in any such action or proceeding shall be conclusive and may be enforced in other jurisdictions by suit on the judgment or in any other manner provided by law. Guarantor waives any objection to venue on the basis of forum non conveniens. Guarantor irrevocably consents to the service of process in any action or proceeding by the mailing of copies of such process to Guarantor at its address set forth herein. Guarantor agrees that any action or proceeding brought against the ISO arising out of or relating to this Guaranty shall be brought only in a Massachusetts court or a United States court sitting in Massachusetts. Nothing herein shall affect the right of the ISO to bring any action or proceeding against Guarantor or its property in the courts of any other jurisdictions.

22. Waiver of Jury Trial. GUARANTOR IRREVOCABLY, VOLUNTARILY, AND WITH ADVICE OF COUNSEL WAIVES ANY RIGHTS IT MAY HAVE TO A TRIAL BY JURY IN ANY ACTION ARISING IN CONNECTION WITH THIS GUARANTY OR THE AGREEMENTS.

23. Dispute. Any dispute arising under, out of, in connection with, or relating to this Guaranty, including any dispute or difference concerning the existence, validity, or enforceability of this Guaranty shall be resolved in accordance with the dispute resolution procedures under the ISO Tariff.

IN WITNESS WHEREOF, the undersigned Guarantor has executed this Guaranty as of this _____ day of _____, _____.

[GUARANTOR]

By: _____

Name: _____

Title: _____

ATTACHMENT 9

SAMPLE CORPORATE GUARANTY
(FOREIGN GUARANTOR)

This FOREIGN GUARANTY AGREEMENT, dated [_____], ("Guaranty") is made by **[full legal name of guarantor]**, a **[country of formation and legal form of Guarantor]** ("Guarantor") on behalf of **[full legal name of Market Participant/Non-Market Participant Transmission Customer]**, a **[state of formation and legal form of Customer]** ("Customer"), and in favor of ISO New England Inc. (the "ISO"), a Delaware nonprofit corporation. Capitalized terms used herein shall have the meaning specified in Section I of the ISO New England Transmission, Markets, and Services Tariff (the "ISO Tariff").

WHEREAS, Customer seeks [to participate in the markets administered by the ISO and purchase other services in the ISO Control Area] [to obtain transmission service in the ISO Control Area]; and

WHEREAS, Customer seeks [to establish a "Market Credit Limit" and a "Transmission Credit Limit" under the ISO New England Financial Assurance Policy (the "Financial Assurance Policy")] [to satisfy the capitalization requirements under the ISO New England Financial Assurance Policy (the "Financial Assurance Policy")] through the provision of a corporate guaranty;

WHEREAS, **[description of Guarantor's legal affiliation with Customer]**; and

WHEREAS, Customer's [participation in the ISO markets] [receipt of transmission service in the ISO Control Area] will directly or indirectly benefit Guarantor.

NOW, THEREFORE, in consideration of the foregoing and the benefits to Guarantor arising from its relationship with Customer, Guarantor hereby agrees and covenants as follows:

1. Guaranteed Amounts. Guarantor unconditionally and irrevocably guarantees the prompt and complete payment of all amounts that Customer now or hereafter owes pursuant to the ISO Tariff, the Financial Assurance Policy, the ISO New England Billing Policy, the NEPOOL Agreement, the Participants Agreement and any other agreements, whether now existing or hereafter arising, between Customer and either the ISO or the NEPOOL Participants, as those tariffs, policies and agreements may be amended from time to time (collectively referred to as "the Agreements"); provided, however, that the aggregate amount guaranteed by Guarantor under this Guaranty shall not exceed $[_____].

2. Term of Guaranty. This Guaranty shall continue in full force and effect until the earlier of (a) the date on which the Agreements are terminated with respect to Customer and all amounts owed by Customer pursuant to the Agreements are paid in full, including any amounts owed as a result of true-ups or other corrections to settlements of obligations owed or incurred while the Agreements and this Guaranty are in effect and (b) **[date]**. This Guaranty may be enforced by the ISO from time to time and as often as occasion for such enforcement may arise prior to the expiration or termination hereof. Guarantor's liability hereunder shall survive the expiration or termination hereof and remain in full force and effect as to obligations owed or incurred by

Customer during the term of this Guaranty. This Guaranty shall survive and continue to bind Guarantor following any merger, reorganization, consolidation, or other change in Customer's or Guarantor's structure or business affairs.

3. Termination of Guaranty. Guarantor may terminate this Guaranty upon sixty (60) days written notice to the ISO.

4. Guaranty of Payment. This is a guaranty of payment and not of collection. If Customer fails to make any payment when due in strict accordance with the Agreements, Guarantor, upon demand, without any notice other than such demand, and without any further action by the ISO, shall make such payment not later than 5:00 p.m. (eastern prevailing time) on the next business day after such demand is made.

5. Obligations Unconditional. This Guaranty is a primary, absolute, unconditional, and continuing guaranty of the full and punctual payment by Customer of its obligations under the Agreements. Guarantor unconditionally guarantees the prompt and complete payment of all amounts owed by Customer under the Agreements if all or any part of such amounts is not paid by Customer when due. The ISO may from time to time, without notice or demand, and without affecting Guarantor's liability hereunder: (i) renew, extend, or otherwise change the terms of the Agreements and (ii) take and hold other security or financial assurance for this Guaranty or the Agreements and exchange, waive, release, or apply such security or financial assurance as the ISO deems appropriate in its sole discretion. Guarantor's liability under this Guaranty is not conditioned upon the validity or enforceability of the Agreements. Guarantor irrecoverably waives presentment, diligence, demand, protest or other notice of any kind, including, without limitation, notice of acceptance of this Guaranty and notice of any claim or demand upon Customer or Guarantor, it being understood that Guarantor waives all suretyship defenses generally.

6. Additional Security. This Guaranty shall be in addition to, and not in substitution for or degradation of, any other security or financial assurance that the ISO may at any time hold in respect of the obligations of Customer under the Agreements. The ISO may enforce this Guaranty notwithstanding that it may hold any guarantee, lien, security of or for Customer under the Agreements, or have available to it any other remedy at law or equity.

7. Expenses. Guarantor shall pay on demand all reasonable costs incurred by the ISO in the enforcement of this Guaranty, including attorney fees and expenses.

8. ISO Remedies; No Set-Off. The rights and remedies of the ISO under this Guaranty are cumulative and concurrent and shall not be exclusive of any other rights or remedies that the ISO may have against Customer or Guarantor. No set-off, counterclaim, or defense of any kind that Guarantor may have against Customer or any other guarantor shall diminish or impair the rights and remedies of the ISO and the obligations of Guarantor hereunder.

9. Bankruptcy. In the event that, pursuant to any insolvency, bankruptcy, reorganization, receivership, or other debtor relief law or any judgment, order, or decision thereunder, the ISO must rescind or surrender any payment received by the ISO, any prior release or discharge from the terms of this Guaranty shall be nullified and this Guaranty shall be reinstated and remain in

full force and effect. Guarantor shall not prove any claim in competition with the ISO or the NEPOOL Participants regarding any payment under the Agreements in bankruptcy or insolvency proceedings of any nature.

10. Subordination. All indebtedness of Customer to Guarantor is subordinated to indebtedness of Customer to the ISO and the NEPOOL Participants, in each case whether now existing or hereafter arising. So long as there is no default under the Agreements, however, Guarantor may continue to receive and retain payments on the subordinated indebtedness.

11. Subrogation. Guarantor irrevocably waives any right of subrogation to any of the rights, claims, security interests, or liens of the ISO against Customer under the Agreements or in any collateral or other security, and Guarantor shall have no right of recourse, reimbursement, contribution, indemnification, or similar right against Customer or any other guarantor of Customer's payments under the Agreements until all amounts owed by Customer pursuant to the Agreements have been paid in full, including any amounts owed as a result of true-ups or other corrections to settlements of obligations incurred while this Guaranty is in effect. If any amount shall be paid to Guarantor on account of such subrogation rights at any time while any amount is due from Customer under the Agreements, such amount shall be held by Guarantor in trust for the ISO and shall, forthwith upon receipt by Guarantor, be turned over to the ISO in the exact form received by Guarantor (duly indorsed by Guarantor or Customer, if required), to be applied to Customer's obligations under the Agreements.

12. Financial Reporting. Guarantor shall be required to comply with the reporting and other requirements established in the Financial Assurance Policy for Foreign Guarantors. All financial reports and other information submitted to the ISO shall be in the English language.

13. Payments.

a. All payments to the ISO by Guarantor shall made in U.S. dollars to such account in the United States as the ISO may from time to time designate to Guarantor and shall be free and clear of, and without deduction or withholding for or on account of, any present or future income, stamp or other taxes or levies, imposts, duties, charges, fees, deductions or withholdings now or hereafter imposed, levied, collected, withheld or assessed by any governmental authority (collectively, "Taxes"). If any Taxes are required to be withheld from any amounts payable to Guarantor under this Guaranty, the amounts payable shall be increased to the extent necessary to provide the full amount (after payment of all Taxes) owing by Guarantor under this Guarantee.

b. All references in the Agreements and in this Guaranty to sums denominated in dollars or with the symbol "$" refer to the lawful currency of the United States of America.

c. The obligations of Guarantor under this Guaranty shall, notwithstanding judgment in a currency other than U.S. dollars (the "Judgment Currency"), be discharged only to the extent that, on any day following receipt by the ISO of any sum adjudged to be due in the Judgment Currency, the ISO may in accordance with normal banking procedures purchase U.S. dollars with the Judgment Currency. If the amount of U.S. dollars so purchased is less than the sum originally due to the ISO in U.S. dollars, Guarantor agrees, as a separate obligation and notwithstanding such judgment, to indemnify the ISO against such loss.

14. Representations and Warranties. Guarantor represents and warrants to the ISO that:

a. Guarantor is duly organized, validly existing, and in good standing under the laws of the country of its organization. Guarantor has the legal power to execute and deliver this Guaranty and to perform this Guaranty in accordance with its terms. All necessary actions have been taken to authorize the execution and delivery of this Guaranty and performance of this Guaranty in accordance with its terms. This Guaranty is a legal, valid, and binding obligation of Guarantor and is enforceable against Guarantor in accordance with its terms.

b. There is no action or proceeding pending or, to Guarantor's knowledge, threatened before any court, tribunal, arbitrator, or governmental agency that may materially adversely affect Guarantor's ability to perform its obligations under this Guaranty.

c. The financial statements and all other written statements provided by Guarantor to the ISO in connection with this Guaranty and the Agreements are true and accurate in all material respects and do not omit any material fact that, without such fact, would make any part of those statements or this Guaranty misleading. There is no fact that Guarantor has not disclosed in writing to the ISO of which Guarantor is aware or which Guarantor can reasonably foresee that would materially adversely affect Guarantor or the ability of Guarantor to perform its obligations hereunder. At such reasonable times as the ISO requests, Guarantor will furnish the ISO with such other financial information as the ISO may reasonably request.

d. No bankruptcy or insolvency proceedings are pending or, to the best of Guarantor's knowledge, contemplated by or against Guarantor under Title 11 of the United States Code, as now or hereafter in effect, or any other applicable law, domestic or foreign, as now or hereafter in effect, relating to bankruptcy, insolvency, liquidation, receivership, reorganization, arrangement or composition, extension or adjustment of debts, or other debtor relief, or similar laws affecting the rights of creditors.

e. Guarantor is subject to Massachusetts civil and commercial law with respect to its obligations under this Guaranty and has no immunity, sovereign or otherwise, from any suit or proceeding, the jurisdiction of any court, recoupment, setoff, or legal process (and hereby waives any defense of immunity to the extent available to Guarantor). This Guaranty is in proper legal form for enforcement against Guarantor. No filing, recording or notarization of any kind is required for enforcement of this Guaranty. No tax or other charge not already paid must be paid on or as a condition to the enforceability of this Guaranty, and there are no taxes imposed by the country in which Guarantor is organized or has its principal business office on or by virtue of Guarantor's execution or delivery of this Guaranty other than payable by Guarantor and which have already been paid.

15. Assignment. The ISO may assign its rights under this Guaranty without in any way diminishing Guarantor's liability hereunder.

16. Adequacy of Consideration. Guarantor acknowledges that the consideration it has received on account of this Guaranty constitutes adequate consideration for its obligations hereunder. Guarantor acknowledges that the ISO will rely on this Guaranty in allowing

Customer to undertake obligations under the Agreements. Guarantor irrevocably waives any defense to the enforcement of this Guaranty based upon lack of consideration.

17. Communications and Service of Process.

a. Demands, notices, and other communications given to Guarantor shall be deemed effective when received, shall be in writing, and shall be delivered by hand with receipt of delivery or registered mail to the following address: **[Guarantor notice address.]**

b. Notices and other communications given to the ISO shall be deemed effective when received, shall be in writing, and shall be delivered by hand with receipt of delivery or registered mail to the following address:

ISO New England Inc.
Attention: Credit Department
1 Sullivan Rd.
Holyoke, Ma 01040

c. Guarantor shall maintain, at all times, a registered agent in Massachusetts (the "Process Agent"). Guarantor hereby irrevocably appoints its Process Agent as its true and lawful agent and attorney-in-fact in its name, place and stead to accept such service of any and all writs, processes and summonses. Guarantor further agrees that the failure of its Process Agent to give any notice of any such service of process to Guarantor shall not impair or affect the validity of such service or of any judgment based thereon. Guarantor consents and agrees that such service shall constitute in every respect, valid and effective service. Guarantor's Process Agent is set forth below, and Guarantor shall provide the ISO with written notification of any change of its Process Agent or the address thereof.

[PROCESS AGENT]
[ADDRESS]
[TELEPHONE]
[EMAIL]

18. Amendment and Waiver. The terms and provisions of this Guaranty may not be amended or waived without the prior written consent of the ISO and Guarantor.

19. Entire Agreement. This Guaranty embodies the entire agreement between Guarantor and the ISO with respect to the matters set forth herein and supersedes all prior such agreements.

20. Severability. Should any provision of this Guaranty be determined by a court of competent jurisdiction to be unenforceable, all of the other provisions shall remain effective.

21. Choice of Law; Jurisdiction; Venue; and Service of Process. This Guaranty shall be governed by the laws of the Commonwealth of Massachusetts without regard to conflicts of laws principles. Guarantor irrevocably and unconditionally submits to the jurisdiction of any Massachusetts court or any United States court sitting in Massaschusetts over any action or proceeding arising out of or relating to this Guaranty and irrevocably agrees that all claims in

such action or proceeding may be heard and determined by such court. Guarantor agrees that a final judgment in any such action or proceeding shall be conclusive and may be enforced in other jurisdictions by suit on the judgment or in any other manner provided by law. Guarantor waives any objection to venue on the basis of forum non conveniens. Guarantor irrevocably consents to the service of process in any action or proceeding by the mailing of copies of such process to Guarantor at its address set forth herein. Guarantor agrees that any action or proceeding brought against the ISO arising out of or relating to this Guaranty shall be brought only in a Massachusetts court or a United States court sitting in Massachusetts. Nothing herein shall affect the right of the ISO to bring any action or proceeding against Guarantor or its property in the courts of any other jurisdictions.

22. Waiver of Jury Trial. GUARANTOR IRREVOCABLY, VOLUNTARILY, AND WITH ADVICE OF COUNSEL WAIVES ANY RIGHTS IT MAY HAVE TO A TRIAL BY JURY IN ANY ACTION ARISING IN CONNECTION WITH THIS GUARANTY OR THE AGREEMENTS.

23. Dispute. Any dispute arising under, out of, in connection with, or relating to this Guaranty, including any dispute or difference concerning the existence, validity, or enforceability of this Guaranty shall be resolved in accordance with the dispute resolution procedures under the ISO Tariff.

IN WITNESS WHEREOF, the undersigned Guarantor has executed this Guaranty as of this _____ day of _____, _____.

[GUARANTOR]

By: _____

Name: _____

Title: _____

ISO new england

Memo

To: NEPOOL Participants Committee

From: ISO New England Enterprise Risk Management

Date: June 18, 2019

Subject: ISO New England's Role as a Central Counterparty ("CCP") and Concerns with the Corporate Guarantee and Surety Bond Proposal

The proposal by certain market participants to re-introduce corporate guarantees and surety bonds into the ISO New England Financial Assurance Policy ("FAP") as acceptable forms of financial assurance (the "Proposal"), if effectuated, would weaken ISO New England Inc.'s ("ISO-NE") ability to clear the markets in a timely manner and is one ISO-NE does not support.

The proponents (the "Proponents") of the Proposal claim the ability to utilize corporate guarantees and surety bonds *may* provide cost savings to participants and by extension to end users. They also claim that there are consequential benefits to ISO-NE and participants by diversifying the acceptable forms of financial assurance. Although ISO-NE does not agree with these claims, the more critical issue and primary reason that ISO-NE does not support the Proposal is the precipitous funding liquidity risk that the Proposal inflicts on ISO-NE's clearing function.[1] ISO-NE's principal concern with the Proposal is the effect it will have on ISO-NE's ability to clear the markets because of reduced liquidity; secondarily, ISO-NE has concerns with introducing substantially weaker forms of financial assurance which could result in substantial or even catastrophic losses to ISO-NE and market participants.

Role of the Central Counterparty

In 2010, in response to the 2008 financial crisis and subsequent credit crunch, the Federal Energy Regulatory Commission ("FERC") issued Orders 741 and 741-A regarding credit reform in organized wholesale electric markets.[2] In Order 741, FERC explained that reforms were necessary to address the potential for mutualized default risk and, in complying with the Orders, ISO-NE became the central counterparty "for transactions that clear through the Day-Ahead and Real-Time Markets, as well as

[1] The International Monetary Fund has described funding liquidity as "the ability of a solvent institution to make agreed-upon payments in a timely fashion." *See* International Monetary Fund, Containing Systemic Risk and Restoring Financial Soundness (2008). While ISO-NE is not a bank or lending agency, this description is illustrative of the risk to ISO-NE and the New England wholesale electricity markets as the underlying principles of banking liquidity are comparable to a CCP.

[2] *See* Credit Reforms in Organized Wholesale Electric Markets – Order No. 741, 133 FERC 61,060 (2010); Credit Reforms in Organized Credit Reforms in Organized Wholesale Electric Markets – Order No. 741-A, 134 FERC 61,126 (2011).

regional network service transactions and certain bilateral transactions that clear through the ISO-NE settlement systems."[3]

As the CCP for the New England wholesale electricity markets, ISO-NE is responsible for reducing the risk of non-payment, providing a stable and reliable cash clearing function, and protecting the New England wholesale electricity markets from defaults. The most critical function of clearing cash for the wholesale energy markets is ***ensuring a market participant's money gets to them accurately and timely***. In order to perform this function, it is paramount that ISO-NE have access to liquid forms of collateral so that ISO-NE can make each participant "whole" in the event of a market participant payment default. Introducing guarantees and surety bonds severely impacts and substantially reduces ISO-NE's ability to ensure that market participants are timely paid.

Parallel to (and in some cases, prior to) the FERC credit reforms noted above, significant financial system reforms took place as a result of the financial crisis. At the 2009 G-20 Pittsburgh Summit, a group of G20 leaders initiated a paradigm shift establishing that most financial transactions should be cleared through CCPs as a key risk-mitigating measure.[4] Since then, the role and importance of CCPs has grown exponentially, evolving with the markets they serve.[5] Most importantly, CCPs have moved away from extending forms of unsecured credit.[6]

Despite the importance of CCPs as risk mitigators, a large concern continues to percolate; what will happen if a large CCP fails? Upon the occurrence of such failure, the markets could see substantial interruption which would have negative business impacts for market participants. Such failure could also cause market participants to lose confidence in the clearing system performed by ISO-NE which could lead to a breakdown of the entire system as we know it. In fact, the reverberations of the financial crisis of 2008 extended for quite some time. In prudently managing risk, ISO-NE must be cognizant of this potential and the ramifications if ISO-NE is unable to clear the markets because of a material market participant payment default. ISO-NE cannot support a proposal that heightens a risk, that if realized may be catastrophic.

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[3] *See id*; Revisions to the ISO New England Inc. Transmission, Markets and Services Tariff in Compliance with Order Nos. 741 and 741-A; Docket No. ER12-1651-000, page 2 (April 30, 2012).

FERC's Guide to Market Oversight Glossary includes the following definition for the term "Centralized Exchange."

> A market where market participants execute all transactions with the central entity operating under a set of rules (product specifications, execution procedures, credit requirements, dispute resolution, code of conduct, etc.) that apply to a range of products offered to this entity. (e.g., Nymex under CFTC jurisdiction is one such market, regional transmission organizations (RTOs) and independent system operators (ISOs) who run markets under FERC jurisdiction can also be considered centralized exchanges). *See* FERC Market Oversight Glossary; https://ferc.gov/market-oversight/guide/glossary.asp.

[4] *See* Jack Ewing and Milan Schreuer, *How a Lone Norwegian Trader Shook the World's Financial System*, N.Y. Times, May 3, 2019, https://www.nytimes.com/2019/05/03/business/central-counterparties-financial-meltdown.html.

[5] *Id.*

[6] *See id.* (quoting chief executive of Eurex Clearing "Compared to a world that was unsecured and uncollateralized, you have made the financial system much more stable…"); Florian Heider, Collateral, Central Clearing Counterparties and Regulation, European Central Bank Research Bulletin No. 41 (Dec. 6, 2017) ("Collateral is playing an increasing role in many areas of the financial markets.").

Function of ISO-NE's Financial Assurance Policy

The purpose of the FAP is to support the role of ISO-NE as the CCP and ensure that ISO-NE has enough liquid collateral on hand to make the market whole in the event of a participant payment default.[7] To be clear, the ISO-NE's opposition to re-introduce parent guarantees and surety bonds as allowable forms of financial assurance is not solely rooted in issues of the creditworthiness of an entity. ISO-NE's primary concern is the functional liquidity risk the Proposal would impose on ISO-NE's clearing function which is central to the ISO-NE's responsibility as a CCP.

This distinction between credit risk versus liquidity risk has largely been ignored and categorically denied by the Proponents as evidenced, inherently by their Proposal, and specifically in their responses to participant questions. In responding to a participant's questions regarding the Proposal, the Proponents rely on their "belief" that the Proposal would not impact ISO-NE's cash clearing exposure.[8] The Proponents offer no evidence for this belief which demonstrates their lack of recognition and appreciation of the potential negative impacts of their Proposal on ISO-NE's access to liquid collateral and the distinctions between currently accepted forms of collateral and guarantees and surety bonds.

Cost Benefit Analysis of Proposal

The Proponents assert that utilizing guarantees and surety bonds *may* potentially save costs for market participants and consumers. To analyze this assertion, ISO-NE used recent monthly billing data (issued on May 13, 2019) to do a cost benefit analysis and to illustrate the potential impact the Proposal would have on liquid collateral amounts (funds held in BlackRock accounts and letters of credit).

Based on a review of the May 13, 2019 billing data, the 10 market participants with the highest market obligations totaled $346 million, which represented approximately 68% of total market obligations.

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[7] The Overview of the FAP provides:

> The purpose of the ISO New England Financial Assurance Policy is… (iii) to set forth the requirements for alternative forms of security that will be deemed acceptable to the ISO and consistent with commercial practices established by the Uniform Commercial Code **that protect the ISO and the Market Participants against the risk of non-payment by other, defaulting Market Participants or by Non-Market Participant Transmission Customers; (iv) to set forth the conditions under which the ISO will conduct business in a nondiscriminatory way so as to avoid the possibility of failure of payment for services rendered under the Tariff**… (emphasis added)

[8] *See* Proponents Responses to W. Short Questions, April 11, 2019, at Questions 9 & 10; https://www.iso-ne.com/static-assets/documents/2019/04/1b_part_proposal_w_short_answers_questions.pdf.

> [Q] Does the cash clearing exposure to Participants, as a whole, increase or decrease under the proposal? Please explain.
>
> [A] Neither, the Proponents believe that these changes to the forms of financial assurance accepted by ISO-NE do not impact the cash clearing exposure. Both the proposed guarantee and the surety bond language include one-day payment terms and other restrictive clauses. The level of cash clearing exposure associated with a guarantee or surety bond is the same as a letter of credit.

The entire $346 million was secured with cash or by letters of credit in accordance with the existing FAP.

Under the Proposal, ISO-NE estimates that of the top 10 market participants' obligations described above, $163 million of previously secured amounts would potentially be unsecured.[9] According to recent data published by Thomson Reuters, the current cost of a letter of credit is approximately 80 basis points for an A or AA rated entity.[10] Therefore, in this scenario, the cost savings is (.008 x $163 million = $1.3 million) which represents 0.0065% of the total retail market of $20 billion or ***$.09 per year of the average consumer's bill*** assuming an average household consumption of 750 kwh per month.[11]

On the other hand, the total invoiced charges on May 13 for these top 10 market participants was $205 million. Out of this amount, $106 million would be eligible to be satisfied by unsecured forms of financial assurance pursuant to the Proposal and therefore, would be at a much higher risk of creating an inability to clear the markets timely, in the event of a payment default.

ISO-NE's primary defense to mitigate default risk is the liquid collateral that the Proposal seeks to diminish. Beyond that, ISO-NE's lines of defense are thin. Once liquid collateral (BlackRock accounts and letters of credit) is exhausted to cure a default, the other protections to keep the markets whole are limited to the Late Payment Account (late payment fees up to $1 million) and then the Payment Default Shortfall Fund (maximum of $4 million) which is only a short-term solution that must be repaid with the subsequent bill issuance.[12]

As demonstrated by the May bill case study, the cost "savings" of the Proposal are de minimis. ISO-NE has the responsibility to protect the integrity of the wholesale electricity markets and to reject proposals that on balance favor a subset of participants' negligible savings over the security of the wholesale electricity markets.

Corporate Guarantees & Surety Bonds as Collateral

At best, corporate guarantees translate to unsecured credit.[13] And despite attempts by the Proponents to draft language whereby a surety bond or corporate guarantee is equivalent to a letter of credit, in reality in a default situation, neither are equivalent instruments that can provide ISO-NE

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[9] $163 million was estimated assuming that, if available, these participants would use the full $50 million of unsecured credit (the maximum amount allowed) or a lesser amount based on actual financial assurance obligations (if under the cap).

[10] *See* Thomson Reuters Pricing Grid - US: Investment Grade, March 25, 2019, 09:00 AM ET.

[11] Even if the cost of a letter of credit is assumed to be 130 basis points, the cost per year for the average consumer would be $.15. ((.013 x $163 = $2.1 million) which represents 0.01% of the total retail market of $20 billion or ***$.15 per year of the average consumers bill*** assuming an average household consumption of 750 kwh per month.)

[12] *See* ISO New England Billing Policy which is Section ID of the ISO New England Transmission, Markets and Services Tariff (Sections 3 and 4 of the Billing Policy address the Late Payment Account and the Payment Default Shortfall Fund).

[13] *See* Credit Reforms in Organized Wholesale Electric Markets – Order No. 741, 133 FERC 61,060, P. 56 (2010) ("Parent guarantees are simply another form of unsecured credit that will not necessarily protect a market from default by market participants if the parent company experiences financial distress, and the Commission directs ISOs and RTOs to not take them into account in establishing the appropriate level of unsecured credit for a market participant or aggregate cap.").

with the liquidity and assurance needed to timely clear the markets and reduce mutualized default risks or to prevent catastrophic consequences to ISO-NE and market participants.

Letters of credit are well established commercial instruments that guarantee payment on demand to ISO-NE upon presentation. Because letters of credit are independent instruments between ISO-NE and the bank they are virtually free from defense of nonpayment other than fraud. Additionally, letters of credit can be drawn on even when the applicant is subject to a bankruptcy proceeding. Neither surety bonds nor guarantees are independent relationships between ISO-NE and the obligor (*e.g.*, bank, surety, guarantor). ***Both are integrally tied to the market participant's obligations under the Tariff and as a result are subject to a range of defenses of nonpayment and both could present significant issues of liquidity if ISO-NE had to sue to enforce either***.

Furthermore, both may be subject to bankruptcy rules preventing, or delaying payment, in the event of the applicant market participant's bankruptcy. In other words, neither guarantees nor surety bonds provide ISO-NE with the security that it will receive payment in a timely manner.

Conclusion

The Proposal, if effectuated, would dramatically impair ISO-NE's ability to fulfill its CCP role (*i.e.*, the ability to clear the markets in a timely manner). ISO-NE values efforts by market participants that seek to reduce costs, but not at the expense of the introduction of a disproportionate amount of risk. The cost benefit analysis above illustrates that any potential cost savings are far outweighed by the maintenance of a sound CCP.

ISO-NE does not agree with the Proponents' claimed diversification benefits as these corporate guarantees and surety bonds would benefit a small subset of market participants and put the majority of market participants at greater risk to shoulder the burden of material defaults. Furthermore, the efficacy of corporate guarantees and surety bonds, used as financial assurance instruments, in the context of wholesale electricity markets is completely untested; in discussions with other ISOs/RTOs that allow these instruments, ISO-NE learned that there are no examples of enforcing/calling on a surety bonds or guarantees.

To reiterate, ISO-NE, as a CCP, has the responsibility to protect the integrity of the wholesale electricity markets and to reject proposals that undermine the ISO's ability to function as such. The Proposal threatens ISO-NE's access to liquid collateral and would weaken ISO-NE's ability to protect the pool in the event of a payment default. Therefore, ISO-NE does not support any portion of the Proposal.

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Pat Gerity, NEPOOL Counsel

DATE: June 18, 2019

RE: Membership Subcommittee Recommendation Concerning Fuels Industry Participants

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You will be asked at the Summer Meeting to consider limited amendments to the Second Restated NEPOOL Agreement (RNA) definition of, and reference to, Gas Industry Participant (to be renamed "Fuels Industry Participant"). The Membership Subcommittee (Subcommittee) unanimously recommended, at its June 14, 2019 meeting, that the Participants Committee do two things: (1) authorize and direct the Balloting Agent to circulate ballots for approval of the amendments to the RNA; and (2) vote to approve American Petroleum Institute (API) as a Fuels Industry Participant, if NEPOOL approves the amendments and the FERC accepts them. This memorandum briefly summarizes the background and substance of the Subcommittee's recommendations and includes forms of resolution for Participants Committee action. A draft of the proposed amendments is also included with this memorandum.

The limited amendments are proposed to accommodate the membership request of API, which is a national trade association representing companies in the natural gas and oil industry, including producers, refiners, marketers, suppliers, pipeline operators and marine transporters providing natural gas and fuel oil used to generate power for the New England region. API has offices in Connecticut and Massachusetts and advocates for its members in every New England state. API does not meet the eligibility requirements in the RNA for a Gas Industry Participant.

Following consideration of various ways to address API's request, the Subcommittee decided to limit its recommendation to addressing the request before it by expanding the definition of Gas Industry Participant (which the Subcommittee recommends be renamed "Fuels Industry Participant") to cover API. The Subcommittee decided against recommending broader changes at this time to address the potential application for membership by of other types of entities not eligible for membership under the RNA arrangements. The amendments proposed here retain the existing eligibility criteria for Gas Industry Participants, and go on to authorize the Participants Committee to determine on a case-by-case basis whether other applicants such as API should also be approved as a Fuels Industry Participant. Fuels Industry Participants are currently and would remain non-Sector, non-voting members. Application and annual fees are currently and would continue to be $5,000, and no additional contributions to Participant Expenses or any additional financial assurance would be required. All Fuels Industry Participants will receive notice of, materials for, and be permitted to attend as Participants, any Principal Committee meeting.

In the interest of efficiency, the Subcommittee recommends that the Participants Committee determine that API should be approved for membership as a Fuels Industry Participant if the RNA amendments are approved in balloting by NEPOOL and accepted by the FERC. If the NPC approves the forms of resolution below, API's membership request would be filed with the FERC following FERC approval of the RNA amendments without the need for

further NPC action. In the meantime, API would be extended a standing invitation to attend NEPOOL meetings as a guest.

The following two forms of resolutions, either voted separately or together if that is the will of the Committee, could be used to act on the Subcommittee's recommendations:

> RESOLVED that the Participants Committee authorizes and directs the Balloting Agent (as defined in the Second Restated NEPOOL Agreement) to circulate ballots for the approval of changes to the Second Restated NEPOOL Agreement (that define and address the arrangements for Fuels Industry Participants), but with such non-material changes therein as the Chair of the Membership Subcommittee may approve, to each Participant for execution by its voting member or alternate on this Committee or such Participant's duly authorized officer.
>
> RESOLVED, that, subject to Participants Committee approval in balloting and FERC acceptance of the amendments to the Second Restated NEPOOL Agreement regarding Fuels Industry Participants, American Petroleum Institute is determined as permitted by those amendments to be a "Fuels Industry Participant".

1.28A FuelsGas Industry Participant is a Participant that either (i) meets all four of the following criteria: (a) the Participant is engaged in the production, gathering, processing, marketing, or transmission of natural gas for sale at wholesale or retail in one or more of the New England states; and (b) the Participant does not participate directly in the New England Markets; and (c) the Participant is not eligible to join or designate a voting member of a Sector (other than the End User Sector); and (d) the Participant elects to be a treated as a FuelsGas Industry Participant before its membership application is approved by NEPOOL; or (ii) is determined by the Participants Committee to be a Fuels Industry Participant. Notwithstanding any other provision of this Agreement, a FuelsGas Industry Participant shall not have the right to join, or be or vote as a member of, a Sector. A FuelsGas Industry Participant, which is not a Related Person of another Participant, shall have the right however, to appoint to each Principal Committee a non-voting member, and an alternate to that member. Such a non-voting member and alternate shall have all of the rights of any other member of a Principal Committee except the right to vote or to serve as an officer of a Principal Committee.

The first sentence of the last paragraph of § 6.2 would also be amended, so that it reads as follows:

All Participants (other than Data-Only Participants, FuelsGas Industry Participants, GIS-Only Participants, and Provisional Members) have the right to join and be a member of a Sector.

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings as of June 21, 2019

The following activity, as more fully described in the attached litigation report, has occurred since the report dated May 1, 2019 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	RTO Insider Press Policy Complaint (EL18-196)	May 10	Public Citizen requests rehearing of *RTO Insider Complaint Order*
			Jun 7	FERC issues tolling order affording it additional time to consider the Public Citizen request for rehearing
	1	Winter Fuel Security (Chapter 3) (EL18-182)	May 21	FERC Issues notice of ***Jul 15*** public, staff-led meeting (in response to Apr 22 request of ISO-NE, NESCOE and NEPOOL)
	2	206 Proceeding: RNS/LNS Rates and Rate Protocols (EL16-19; ER18-2235)	May 22	FERC rejects Settlement and remands EL16-19 to Chief Judge Cintron for the resumption of hearing procedures; ER18-2235 terminated
			May 23	Chief Judge Cintron designates (i) ALJ David Coffman as the Presiding Judge for purposes of hearing and an initial decision; and (ii) resolution specialist Joshua Hurwitz as the settlement facilitator
			May 24	Presiding Judge Coffman schedules prehearing conference for Jun 6 to establish a procedural schedule that will lead to hearings beginning no later than Mar 12, 2020 and an initial decision by Aug 6, 2020
			Jun 6	Pre-hearing conference held
			Jun 10	Presiding Judge Coffman issues orders establishing a procedural schedule and adopting rules of conduct for the hearings

II. Rate, ICR, FCA, Cost Recovery Filings

*	7	VTransco Tax Rate Attachment F Waiver Request (ER19-1832)	May 13	VTransco requests a waiver of Attachment F to enable it to use the 21% fed. income tax rate in its 2019 revenue requirement calculations
			Jun 11	FERC grants waiver request, eff. Jun 1, 2019
	6	Trans. Rate Incentive Request: UI's Pequonnock Substation Project (ER19-1359)	May 14	FERC issues an order granting UI's requested abandonment plant and CWIP transmission rate incentives, but denying the requested ROE Incentive, eff. May 15
			Jun 14	UI requests rehearing of May 14 order
	7	FCA13 Results Filing (ER19-1166)	May 7	Vineyard Wind answers ISO-NE Apr 29 answer
			May 8	CEA answers responses and comments
			May 10	NEPGA answers ISO-NE and IMM Apr 29 answers; MHPS answers comments made about its turbine technology
			May 14	Capacity Suppliers answer ISO-NE and IMM Apr 29 answers
			May 24	ISO-NE supplements record advising that the "disaggregated quantity of capacity from Demand Capacity Resources at the End-of-Round Price for each Capacity Zone" was not published during FCA 13
			Jun 6	FERC issues deficiency letter; ISO-NE responses due Jul 8
*	10	MPD OATT 2019 Annual Informational Filing (ER15-1429-000)	May 1	Emera Maine submits annual update of charges under the MPD OATT
			May 16	Emera Maine submits revisions to 2019-20 charges
	10	MPD OATT 2018 Annual Informational Filing (ER15-1429-010)	May 7	Chief Judge Cintron designates ALJ John Dring as Settlement Judge
			May 20	Settlement Judge Dring schedules first settlement conf. for Jul 18
			May 31	Settlement Judge Dring issues status report
			Jun 5	Chief Judge issues order continuing settlement judge procedures

*	11	MPD OATT 2018 Annual Info Filing Compliance Filing (ER15-1429-011)	May 16	Emera Maine submits compliance filing in response to requirements of the *2018 Challenge Order*; comment date Jun 6
			May 22	Maine Customer Group protests May 16 compliance filing
			Jun 7	Emera Maine answers MCG's May 22 protest
			Jun 11	MCG moves to strike a portion of Emera Maine's May 1 compliance filing
			Jun 14	MCG answer's Emera Maine's Jun 7 answer

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

*	12	DAM Offer Cap Changes (ER19-2137)	Jun 14	ISO-NE and NEPOOL jointly file changes to revise the dispatch treatment of resources whose Supply Offers are price-capped in the Day-Ahead Energy Market; ISO-NE requests effective date for all *Order 831* changes become eff. Mar 1, 2020; comment date Jul 5
			Jun 17-24	Eversource, Exelon, National Grid intervene
*	12	Waiver Request: FCA14 SOI Deadline (New Brunswick Energy Mktg) (ER19-2011)	May 30	New Brunswick Energy Marketing requests limited waiver of MR1 § 13.1.10 (FCA Qualification Schedule) to allow ISO-NE to accept NB's FCA14 Show of Interest form
			Jun 4-5	NEPOOL, NRG intervene
			Jun 20	FERC grants requested waiver
	12	ISO-NE's Interim Winter Energy Security (Chapter 2B) Proposal (ER19-1428)	May 8	FERC issues deficiency letter
			May 14	MA AG answers ISO-NE Apr 30 answer
			Jun 6	ISO-NE responds to deficiency letter; comment date Jun 27
	14	ISO-NE eTariff Versioning Corrections (ER19-1387)	May 3	FERC accepts changes, eff. Apr 1, 2019
	15	*Order 841* Compliance Filing (ER19-470)	May 3	NPC supports Tariff changes
			May 22	NEPOOL, AEE file comments

IV. OATT Amendments / TOAs / Coordination Agreements

*	20	Interconnection Studies Scope and Reasonable Efforts Timelines Changes (ER19-1952)	May 22	ISO-NE, NEPOOL and PTO AC together file changes to Schedule 22 to: (i) reduce the scope of the Feasibility Study and increase the Reasonable Efforts timeframe for completing that study; and (ii) increase the Reasonable Efforts timeframe for completing the System Impact Study
			May 30-Jun 17	Avangrid, Calpine, Dominion, EDP, National Grid, NRG intervene
			May 31	AWEA requests 21-day extension of comment date
			Jun 7	FERC grants 14-day extension of comment date (to Jun 26)
*	20	ISO-NE *Order 845* Compliance Filing (ER19-1951)	May 22	ISO-NE and PTO AC jointly file *Order 845* Changes
			May 24-Jun17	NEPOOL, Avangrid, Calpine, Dominion, EDP, Eversource, MA AG, National Grid, NRG, ESA intervene
			May 31	AWEA requests 21-day extension of comment date
			Jun 5	NEPOOL submits comments and protest
			Jun 7	FERC grants 14-day extension of comment date (to Jun 26)

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Changes

*	21	Schedule 21-UI: LCSA Cancellation - UI/EES5 (Bridgeport Energy) (ER19-1921)	May 21	UI files to cancel LCSA with EES5 in light of transfer of Category B Network Load Responsibility for the Bridgeport Energy facility to Revere Power

*	21	Schedule 21-UI: LCSA - UI/Revere Power (Bridgeport Energy) (ER19-1911)	May 21	UI files LCSA with Revere Power to recover Bridgeport Energy's Category B Load Ratio Share of the revenue requirement for UI's Localized Facilities under Schedule 21-UI
	21	Schedule 21-NEP: National Grid/Calpine Fore River RFA (ER19-1681)	Jun 18	FERC accepts RFA, eff. Mar 28, 2019
	21	Schedule 21-EM: BHD Excess ADIT Changes (ER19-1470)	May 6 May 10 May 28 Jun 10	Emera Maine answers MPUC Apr 19 comments FERC issues deficiency letter; Emera Maine responses due Jun 10 MPUC withdraws its Apr 19 comments Emera Maine submits responses to May 10 deficiency letter; comment date Jul 1
	21	Schedule 21-EM: MPD Excess ADIT Changes (ER19-1400)	May 10 Jun 7	FERC issues deficiency letter Emera Maine submits responses to May 10 deficiency letter
*	23	Schedule 21-EM 2019 Annual Informational Filing (ER15-1434)	Jun 10	Emera Maine submits annual update to its local transmission service rates
*	22	Schedule 21-EM: 2018 Annual Update Settlement Agreement (ER15-1434-003)	May 24	Emera Maine files Settlement Agreement to resolve a majority of the issues raised by the MPUC following its 2018 Annual Update filing
*	23	Schedule 21-NSTAR Annual Informational Filing (ER09-1243; ER07-549)	May 31	NSTAR submits an informational filing containing the true-up of billings under Schedule 21-NSTAR for the Jan1, 2018 through Dec 31, 2018 period
*	23	Schedule 21-GMP: Annual True Up Calculation Informational Filing (ER12-2304)	May 31	GMP submits annual info filing containing true-up calculation of its actual costs for the Jan 1, 2018 through Dec 31, 2018 period

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

*	24	Capital Projects Report - 2019 Q1 (ER19-1822)	May 10 May 16 May 16-28 Jun 21	ISO-NE files 2019 Q1 Report NEPOOL intervenes and files comments supporting Q1 Report Calpine, Eversource, National Grid intervene FERC accepts the 2019 Q1 Report, eff. Apr 1, 2019
*	25	IMM Quarterly Markets Reports - 2019 Winter (ZZ19-4)	May 7	IMM files Winter 2019 Report
*	25	IMM 2018 Annual Markets Report (ZZ19-4)	May 23	IMM files annual report covering calendar year 2018
*	26	ISO-NE 2018 FERC Form 714 (not docketed)	May 31 Jun 3	ISO-NE submits 2018 FERC Form 714 ISO-NE submits revised 2018 FERC Form 714

IX. Membership Filings

*	26	June 2019 Membership Filing (ER19-2021)	May 31	*New Members*: Brookfield Renewable Trading and Marketing; Community Eco Power; DWW Solar II; NS Power Energy Marketing; *Terminations*: Mint Energy, Power Bidding Strategies and Utility Expense Reduction; *Name Change*: Bridgeport Fuel Cell;
	26	Michael Kuser Membership Filing (ER19-1737)	Jun 18	FERC accepts End User membership

	26	May 2019 Membership Filing (ER19-1720)	Jun 18	FERC accepts the May 1, 2019 memberships of AES Distributed Energy and Precept Power; the Apr 1, 2019 termination of Tomorrow Energy; and the name changes of Central Rivers Power NH and NGV US Transmission
	26	Involuntary Termination: Lotus Danbury LMS100 One (ER19-1550)	Jun 3	FERC accepts involuntary termination of NEPOOL and ISO-NE Market Participant status, eff. Jun 10, 2019
*	27	Suspension Notice – Stored Solar J&WE (not docketed)	Jun 6	ISO-NE files notice of Jun 4 suspension of Stored Solar J&WE from the New England Markets
*	27	Suspension Notice – Great American Power (not docketed)	May 13	ISO-NE files notice of May 9 suspension of Great American Power from the New England Markets

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

*	27	Revised Reliability Standard: CIP-003-8 (RD19-5)	May 21	NERC files revised standard for approval
*	27	Revised Reliability Standard: CIP-008-6 (RD19-3)	Jun 20	FERC approves CIP-008-6, eff. Jan 1, 2021
*	27	Revised Reliability Standards: FAC-008-4; INT-006-5; INT-009-3; PRC-004-6; Retirement of 10 Standards (Standards Efficiency Review II) (RM19-17)	Jun 7	FERC files for approval, in connection with its Standards Efficiency Review, retirement of (i) requirements in 4 Reliability Standards and (ii) 10 Reliability Standards in their entirety
*	28	Revised Reliability Standards: IRO-002-7; TOP-001-5; VAR-001-6 (Standards Efficiency Review I) (RM19-16)	Jun 7	FERC files for approval, also in connection with its Standards Efficiency Review, retirement of requirements in 3 Reliability Standards
*	28	NOPR - Revised Reliability Standard: TPL-001-5 (RM19-10)	Jun 20	FERC issues *TPL-001-5 NOPR*; comment date [60 days after publication in the *Federal Register*], which has not yet happened
	29	NOPR - New Reliability Standard: CIP-012-1 (RM18-20)	May 21	J. Appelbaum submits comments Comments received from C. Liu, VA Tech Power and Energy Center
*	29	Report of Comparisons of 2018 Budgeted to Actual Costs for NERC and its Reg. Entities (RR19-6)	May 30	FERC files report

XI. Misc. - of Regional Interest

*	29	203 Application: Footprint, Hartree Partners / Brookfield (EC19-104)	Jun 19	Footprint and Hartree Partners, among others, and Brookfield request authorization for transaction in which these Participants, through Oaktree Capital Group, will become Related Persons; comment date Jul 10
*	29	203 Application: Empire Generating Co, LLC (EC19-99)	Jun 4	Empire requests authorization for the disposition of its FERC-jurisdictional facilities by way of a bankruptcy-related upstream change in control; comment date Jun 25
			Jun 17	Empire amends application; comment date Jul 8
			Jun 21	FERC issues deficiency letter; Empire responses due Aug 5
*	30	203 Application: Kendall Green Energy (EC19-86)	May 6	Kendall Green requests authorization for transaction in which Veolia will become the sole owner through the acquisition of ISQ Thermal Kendall's 49% share

*	30	203 Application: Convergent Energy and Power / ECP (EC19-85)	May 3 May 23-24 Jun 20	Convergent requests authorization for its acquisition by ECP (upon which it will become a Calpine Related Person) PJM, PJM IMM intervene FERC authorizes transaction
	30	203 Application: Emera Maine/ENMAX (EC19-80)	May 1-10	Eastern Maine Electric Cooperative, MPUC, NMISA intervene
	31	203 Application: Dominion Bridgeport Fuel Cell (EC19-22)	May 9 May 17	FuelCell Energy Finance acquires Dominion Bridgeport Fuel Cell Dominion Bridgeport Fuel Cell submits consummation notice
	31	New England Ratepayers Association Complaint (EL19-10)	May 6	New Hampshire congressional delegation sends letter to FERC Chairman urging the FERC to "swiftly act on this [11/2/2018] petition"
	31	PJM MOPR-Related Proceedings (EL18-178; ER18-1314; EL16-49)	May 9	EPSA protests PJM Entities' Apr 25 answer
*	34	PJM Retroactive Surcharges (EL08-14)	Jun 20	FERC reverses its prior position on the issue of ordering refunds in cost allocation and rate design cases, and finds that it does in fact have authority under the FPA to order refunds to fix an error, even if refunds will require surcharges on other parties
*	35	D&E Agreement: NSTAR/Vineyard Wind (ER19-2171)	Jun 17	NSTAR files Agreement; comment date Jul 8
*	35	RFA Termination: NSTAR/Pilgrim (ER19-2108)	Jun 11	NSTAR files notice of the Jun 1, 2019 termination of the Pilgrim RFA; comment date Jul 2
*	35	IA Termination: Pilgrim Nuclear Power Station/NSTAR (ER19-2046)	Jun 4	NSTAR files notice of the Jun 1, 2019 termination of the Pilgrim Interconnection and Operation Agreement; comment date Jun 25
*	35	Emera Maine/Houlton Water Company NITSA (ER19-2036)	Jun 3	Emera Maine files non-conforming Network Integration Transmission Service Agreement with Houlton Water Co.
*	35	D&E Agreement: CL&P/NTE CT (ER19-1994)	May 28	CL&P files Agreement
	36	Emera Maine *Order 845* Compliance Filing (ER19-1887)	May 17 Jun 13	Emera Maine submits filing FERC requests additional information; responses due Jul 15
	36	D&E Agreement Cancellation: NSTAR/National Grid (Wynn Casino) (ER19-1395)	May 7	FERC accepts notice of cancellation, eff. Mar 21, 2019
	36	CMP & UI/Brookfield Phase I/II HVDC-TF Service Agreements (ER19-1105 et al.)	May 2	FERC accepts agreements, eff. Jan 1, 2020 (1105 & 1106) and Sep 1, 2020 (1107)
*	37	FERC Enforcement Action: Dominion Energy Virginia (IN19-3)	May 3	FERC approves Stipulation and Consent Agreement with DEV, requiring DEV to pay a ***$7 million civil penalty*** and to ***disgorge $7 million***, including interest, to resolve the FERC's investigation into violations, between 2010 and 2011,of the FERC's Anti-Manipulation Rules

XII. Misc. - Administrative & Rulemaking Proceedings

	39	Increasing Market and Planning Efficiency Through Improved Software (AD10-12)	May 24 Jun 20	FERC issues initial Jun 25-27 tech. conf. agenda FERC issues final Jun 25-27 tech. conf. agenda
	39	NOPR: Refinements to Horizontal Market Power Analysis Requirements (RM19-2)	May 7 May 23	PJM answers PJM IMM's Mar 18 comments PJM IMM answers PJM's May 7 answer

	40	*Orders 845/845-A*: LGIA/LGIP Reforms (RM17-8)	May 20 May 21	*Order 845-A* becomes effective AWEA answers AEP's Mar 21 request for reh'g
	41	*Orders 841/841-A*: Electric Storage Participation in RTO/ISO Markets (RM16-23; AD16-20)	May 16	FERC issues *Order 841-A,* denying the requests for rehearing of *Order 841*, and denying in part but granting in part the requests for clarification of *Order 841*
*	43	NAESB WEQ v. 003.2 NOPR (RM05-5-027)	May 16 Jun 5	FERC issues NOPR proposing to incorporate by reference into its regs, with certain exceptions, the Version 003.2 WEQ Standards; comment date Jul 23, 2019 NAESB submits comments
	43	NOI: FERC's ROE Policy (PL19-4)	May 10 May 21 May 20-Jun 18	APPA, EEI and NRECA request extension of time to file reply comments FERC denies extension of time to file reply comments (which remain due Jun 26, 2019) Individuals file comments
	43	NOI: Electric Transmission Incentives Policy (PL19-3)	May 10 May 21 Jun 18	APPA, EEI and NRECA request extension of time to file reply comments FERC grants extension of time for reply comments, now due Aug 26; initial comments remain due Jun 26, 2019 R Street Institute files comments

XIII. Natural Gas Proceedings

No Activity to Report

XIV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XV. Federal Courts

43	PennEast Project (18-1128)	May 2 May 8 Jun 4 Jun 6	Petitioners file Joint Reply Brief Appellants file Joint Reply Brief Petitioners file final Joint Reply Brief Appellants file final Joint Reply Brief; Amicus briefs filed

M E M O R A N D U M

TO: NEPOOL Participants Committee Member and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: June 24, 2019

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 21, 2019. If you have questions, please contact us.

I. Complaints/Section 206 Proceedings

- **RTO Insider Press Policy Complaint (EL18-196)**

As reported in the April 10 Report, the FERC dismissed, on April 10, 2019, *RTO Insider*'s August 31 Complaint.[2] The Complaint had requested that the FERC either (i) find that NEPOOL's press policy "unlawful, unjust and unreasonable, unduly discriminatory and contrary to the public interest, and direct NEPOOL to cease and desist" from implementing its policy; or (ii) "if the [FERC] finds that NEPOOL can sustain such a ban as a "private" entity, [] direct that NEPOOL's special powers, privileges and subsidies be terminated and that an open stakeholder process be used by [ISO-NE]" ("RTO Insider Complaint"). In dismissing the RTO Insider Complaint, the FERC agreed with NEPOOL that the claims asserted by RTO Insider did not relate to matters over which the FERC has jurisdiction, finding that the "rules governing attendance at NEPOOL meetings do not directly affect the filings brought before the Commission in the way that membership rules that allow members to vote do … the challenged NEPOOL policies here concern passive attendance at NEPOOL meetings by non-voting entities and dissemination of written accounts of NEPOOL deliberations. The contested attendance and reporting policies are too attenuated from NEPOOL's voting process to directly affect jurisdictional rates." On May 10, Public Citizen requested rehearing of the *RTO Insider Complaint Order*. On June 7, the FERC issued a tolling order affording it additional time to consider the request for rehearing, which remains pending. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Winter Fuel Security (Chapter 3) (EL18-182)**

As previously reported, the July 2, 2018 *Mystic Waiver Order*[3] (reported on in more detail in ER18-1509 in Section III below) in part instituted this Section 206 proceeding in light of the FERC's preliminarily finding that the ISO-NE Tariff may be unjust and unreasonable in that it fails to address specific regional fuel security concerns identified in the record in ER18-1509 that could result in reliability violations as soon as 2022. Accordingly, the *Mystic Waiver Order* directed ISO-NE, in part, to submit permanent Tariff revisions reflecting improvements to its market design to better address regional fuel security concerns (the "Chapter 3 Proposal"). Following an ISO-NE request for an extension of time to file its Chapter 3 Proposal, the FERC issued a notice granting an extension of

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

[2] *RTO Insider LLC v. New England Power Pool Participants Comm.*, 167 FERC ¶ 61,021 (Apr. 10, 2019) ("*RTO Insider Complaint Order*").

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

time, to and including ***October 15, 2019***, a month earlier than requested, for the filing of that Proposal. The schedule for development and consideration of the Chapter 3 mechanism has been adjusted accordingly.

July 15 Technical Conference. On May 21, the FERC issued a notice that it will hold a public, staff-led meeting on July 15 at FERC headquarters. The meeting is in response to the April 22 joint request by ISO-NE, NECPUC and NEPOOL for a meeting (albeit during the week of July 22) to create a forum for pre-filing discussions without violating the *ex parte* limitations. The July 15 meeting will begin at 10:00 am (ET) at FERC headquarters and will consist of three, 90-minute presentations by ISO-NE, NEPOOL stakeholders and representatives from New England states, with time for questions from FERC Staff and Commissioners only reserved at the end of the meeting. Further details will be outlined in a future notice.

If you have any questions concerning this proceeding, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **206 Proceeding: RNS/LNS Rates and Rate Protocols (EL16-19-002)**

Concluding that the contested 2018 Joint Offer of Settlement (the "Settlement"),[4] filed to resolve all issues in the Section 206 proceeding instituted by the FERC on December 28, 2015,[5] lacked sufficient detailed information to enable it to apply any of the approaches available to it to approve a contested settlement,[6] the FERC rejected the Settlement and remanded this proceeding (EL16-19) to Chief Judge Cintron to resume hearing procedures.[7] The *RNS Rate/Rate Protocol Settlement Order* terminated Docket No. ER18-2235.

As previously reported, the Settlement was supported by ***NESCOE*** but opposed by Municipal PTF Owners[8] and FERC Trial Staff. The ***Municipal PTF Owners*** ("Munis") asserted that the Settlement would worsen, rather than improve, the issues of "lack of transparency, clarity and specificity that led the Commission [to] find the existing Attachment F formula unjust and unreasonable", discriminate against load directly connected to PTF and exempted by Section II.12(c) of the ISO-NE Tariff from paying costs associated with service across non-PTF facilities, contravened numerous settled rate principles without explanation or justification,[9] and would have

[4] As previously reported, the Settling Parties filed the Settlement on Aug. 17, 2018, in ER18-2235. The Settlement proposed changes to Section II.25, Schedules 8 and 9, Attachment F (including the addition of Interim Formula Rate Protocols ("Interim Protocols")), and the Schedule 21s to the ISO-NE OATT. Had they been approved, the changes to Attachment F would have become effective mid-June, 2019, with the remaining changes to be effective January 1, 2020. The Interim Protocols, as well as the changes to Section II.25 and Schedules 8 and 9, were supported by the Participants Committee at its July 24, 2018 meeting.

[5] *ISO New England Inc. Participating Transmission Owners Admin. Comm.*, 153 FERC ¶ 61,343 (Dec. 28, 2015), *reh'g denied,* 154 FERC ¶ 61,230 (Mar. 22, 2016) ("*RNS/LNS Rates and Rate Protocols Order*"). The *RNS/LNS Rates and Rate Protocols Order* found the ISO-NE Tariff unjust, unreasonable, and unduly discriminatory or preferential because the Tariff "lacks adequate transparency and challenge procedures with regard to the formula rates" for Regional Network Service ("RNS") and Local Network Service ("LNS"). The FERC also found that the RNS and LNS rates themselves "appear to be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful" because (i) "the formula rates appear to lack sufficient detail in order to determine how certain costs are derived and recovered in the formula rates" and "could result in an over-recovery of costs" due to the "the timing and synchronization of the RNS and LNS rates". The FERC encouraged the parties to make every effort to settle this matter before hearing procedures are commenced. The FERC-established refund date is January 4, 2016.

[6] The FERC outlined in a seminal case the following four alternative approaches for approving contested settlements: (1) where the FERC can render a binding merits decision on each contested issue, (2) where the FERC can approve the settlement based on a finding that the overall settlement *as a package* is just and reasonable, (3) where the FERC can determine that the benefits of the settlement outweigh the nature of the objections and the interests of the contesting party are too attenuated, and (4) where the FERC can approve the settlement as uncontested for the consenting parties, and can sever the contesting parties to allow them to litigate the issues raised. *See Trailblazer Pipeline Co.*, 85 FERC ¶ 61,345, at 62,342-44 (1998).

[7] *ISO New England Inc. Participating Transmission Owners Admin. Comm., et al.*, 167 FERC ¶ 61,164 (May 22, 2019) ("*RNS Rate/Rate Protocol Settlement Order*"). The Parties were reminded that they could seek further settlement judge procedures as well. *Id.* at fn. 49.

[8] "Municipal PTF Owners" are: Braintree, Chicopee, Middleborough, Norwood, Reading, Taunton, and Wallingford.

[9] The elements of the Settlement that Municipal PTF Owners assert contravene settled rate principles include: provision for a fixed accrual for Post-Employment Benefits Other than Pension ("PBOPs"); continued TO use of net proceeds of debt, rather than gross

imposed an unacceptable moratorium and burden on parties inclined to challenge Attachment F. ***FERC Trial Staff*** asserted that the Settlement, as filed, was not fair and reasonable nor in the public interest "because it would result in unreasonable rates and contains fundamental defects",[10] and opposed the Settlement terms which would bind non-settling parties to the terms of the Settlement and establish a standard of review for changes to the Settlement. FERC Trial Staff suggested that these defects could be corrected in a comprehensive compliance filing. ***Reply comments*** were submitted by NEPOOL, NESCOE and the MA AG. In its limited comments, ***NEPOOL*** noted that it supported the Interim Protocols and that it had no objection to the Settlement. ***NESCOE*** reiterated its support for the Settlement in its reply comments, urging the FERC to reject any arguments that consumer-interested parties "were not familiar with the issues relating to the Settlement or that they reached a settlement for any reason other than their view that it is in the best interests of consumers."[11] ***MA AG*** urged the FERC to approve the Settlement as submitted, despite the objections of FERC Trial Staff and Municipal PTF Owners, because it complies with the *RNS/LNS Rates and Rate Protocols Order* and represents a carefully negotiated resolution to numerous complex ratemaking and transparency issues.[12]

Hearings. Having rejected the Settlement, the FERC remanded this proceeding to Chief ALJ Cintron to resume hearing procedures. On May 23, Chief Judge Cintron designated Judge David H. Coffman as the Presiding Judge for the purpose of hearings and issuance of an initial decision within Track III procedural time standards.[13] A prehearing conference was held on June 6, 2019. Following that conference, orders establishing a procedural schedule and adopting rules of conduct for the hearing were issued. Hearings are scheduled to begin March 12, 2020, with an initial decision issued by August 6, 2020. Interim deadlines of interest include the deadlines for direct testimony (Aug 29); answering testimony (Nov 26); rebuttal testimony (Jan 15, 2020); pre-hearing briefs (Feb 25); initial briefs (Apr 27); reply briefs (Jun 2); and oral arguments on the merits (Jun 9). Discovery is on-going.

If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Jamie Blackburn (202-218-3905; jblackburn@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,[14] set the TOs' Base ROE at 10.57% (reduced from 11.14%), capped the TOs' total ROE (Base ROE *plus* transmission incentive adders)

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proceeds of debt, in establishing capital structures under their proposed revenue requirement formula; inappropriate allocation of rental revenues from secondary uses of transmission facilities; the addition of miscellaneous intangible plant (Account 303), and depreciation and amortization of intangibles, to rate base; and the creation of a Regulatory Asset for an unspecified Massachusetts state tax rate change (without explanation).

[10] Included in the "fundamental defects" of the Settlement identified by FERC Trial Staff are that it: (1) enables the TOs to conduct extra-formulaic, ad hoc ratemaking for all externally-sourced inputs every year; (2) enables certain PTOs to over-recover certain plant costs; (3) enables certain PTOs to recover greater than 50% of Construction Work in Progress ("CWIP") in rate base (4) violates prior FERC orders about which customer groups can be made to pay incentive returns; (5) fails to appropriately calculate federal and state income taxes and, in particular, fails to account for excess Accumulated Deferred Income Taxes ("ADIT") created by the Tax Cuts and Jobs Act; (6) does not contain a fixed and stated ROE; and (7) does not contain a fixed and stated PBOPs expense.

[11] Reply Comments of NESCOE, Docket Nos. ER18-2235 and EL16-19, at p. 2 (filed Sep. 28, 2018).

[12] Reply Comments of the Mass. Att'y General in Support of Settlement, Docket Nos. EL16-19 and ER18-2235 (filed Sep. 28, 2018).

[13] Track III time standards require a hearing be convened within 42 weeks and an initial decision issued within 63 weeks.

[14] 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 clarific.*, 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*")).

at 11.74%, and required implementation effective as of October 16, 2014 (the date of *Opinion 531-A*).[15] However, the FERC's orders were challenged, and in *Emera Maine,*[16] the DC Circuit Court 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)[17] and third (EL14-86)[18] 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.[19] 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[20] also went to hearing before an ALJ, Judge Glazer, who issued his initial decision on March 27, 2017.[21] 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.[22] 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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[15] *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*").

[16] *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).

[17] 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% return on equity, and seeks a reduction of the Base ROE to 8.7%.

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

[19] *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*").

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

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

[22] *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.[23] The FERC indicated its intention that the methodology be its policy going forward, including in the four currently pending New England proceedings. The FERC established a paper hearing on how its proposed methodology should apply to the four pending ROE proceedings.[24]

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%.[25] The new ROE would be effective as of the date of *Opinion 531-A*, or October 16, 2014. Accordingly, the issue to be addressed in the Base ROE Complaint II proceeding is whether the ROE established on remand in the first complaint proceeding remained just and reasonable based on financial data for the six-month period September 2013 through February 2014 addressed by the evidence presented by the participants in the second proceeding. Similarly, briefing in the third and fourth complaints will have to address whether whatever ROE is in effect as a result of the immediately preceding complaint proceeding continues to be just and reasonable.

The FERC directed participants in the four proceedings to submit briefs regarding the proposed approaches to the FPA section 206 inquiry and how to apply them to the complaints (separate briefs for each proceeding). Additional financial data or evidence concerning economic conditions in any proceeding must relate to periods before the conclusion of the hearings in the relevant complaint proceeding. Following a FERC notice granting a request by the TOs and Customers[26] for an extension of time to submit briefs, the latest date for filing initial and reply briefs was extended to January 11 and March 8, 2019, respectively. On January 11, initial briefs were filed by EMCOS, Complainant-Aligned Parties, TOs, EEI, Louisiana PSC, Southern California Edison, and AEP. As part of their initial briefs, each of the Louisiana PSC, SEC and AEP also moved to intervene out-of-time. Those interventions were opposed by the TOs on January 24. The Louisiana PSC answered the

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

[24] *Id.* at 19.

[25] *Id.* at P 59.

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

TO's January 24 motion on February 12. Reply briefs were due March 8, 2019 and were submitted by the TOs, Complainant-Aligned Parties, EMCOS, FERC Trial Staff. This matter is pending before the FERC.

These matters are now pending before the FERC. If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com), Joe Fagan (202-218-3901; jfagan@daypitney.com) or Jamie Blackburn (202-218-3905; jblackburn@daypitney.com).

II. Rate, ICR, FCA, Cost Recovery Filings

- **Transmission Rate Incentive Request: UI's Pequonnock Substation Project (ER19-1359)**

On May 14, the FERC issued an order granting two of the three transmission rate incentives[27] requested by UI in connection with its Pequonnock Substation Project.[28] The FERC granted both the requested Abandoned Plant Incentive[29] and the CWIP Incentive.[30] The FERC denied, however, UI's request for an ROE Incentive Adder.[31] In denying the ROE Incentive Adder request, the FERC agreed with State Parties[32] and found that (i) the smart grid technology that UI plans to use for the Project was not sufficiently novel or innovative to satisfy the required showing under the FERC's 2012 Policy Statement and (ii) its "hardened resilient design" was a conventional design, and did not demonstrate risks and challenges not otherwise accounted for in UI's base ROE or addressed through risk-reducing incentives.[33] The incentives granted were granted under *Order 679*. In response to the procedural arguments challenging Public Citizen's intervention, the FERC found that "good cause exists to grant Public Citizen's motion to intervene, based on Public Citizen's representations".[34] The FERC accepted the Abandoned Plant and CWIP Incentives effective as of May 15,

[27] Pursuant to section 219 of the FPA, the FERC, in *Order 679*, set forth processes by which a public utility may seek incentive-based rate treatments to promote capital investment in certain transmission infrastructure. Incentive rate treatment is available to applicants that show that the facilities for which incentives are sought "either ensure reliability or reduce the cost of delivered power by reducing transmission congestion." There is a rebuttable presumption that the showing has been made if: (1) the transmission project results from a fair and open regional planning process that considers and evaluates the project for reliability and/or congestion and is found to be acceptable to the FERC; or (2) a project has received construction approval from an appropriate state commission or state siting authority. The FERC a project-specific demonstration of the nexus between the requested incentives and the risks and challenges of the project. In November 2012, the FERC issued the 2012 Policy Statement providing additional guidance regarding its evaluation of applications for transmission rate incentives under section 219 and *Order 679*.

[28] *United Illuminating Co.*, 167 FERC ¶ 61,126 (May 14, 2019) ("*UI Pequonnock Rate Incentive Order*"). As previously reported, UI's Pequonnock Substation Project will replace the existing Pequonnock substation and will include (1) a new 115-kV/13.8-kV gas insulated substation; (2) the relocation and installation of five existing 115-kV overhead transmission lines including seventeen new galvanized steel monopole structures (ten single circuit, two double circuit, and five "walk down" 11 structures); and 3) the relocation and installation of two 115-kV underground high-pressure gas filled cables and one underground XLPE cable, each ranging in length from about 500 to 730 feet. The Pequonnock Substation Project is approximately a $101.6 million electric transmission investment and is expected to be placed in service on or before Dec. 1, 2022.

[29] 100% recovery of prudently incurred costs in the event the Pequonnock Substation Project is abandoned, in whole or in part, for reasons outside of UI's reasonable control.

[30] Inclusion of 100% of Construction Work in Progress ("CWIP") in rate base.

[31] The ROE Incentive Adder would have been a 50 basis point return on common equity for increased risks and challenges prompted by UI's deployment of smart grid communications-enabled technology and construction and operation of a substation that includes a resilient design. The FERC also declined to grant the ROE Incentive Adder under its section 205 authority (which it has previously held it can do under certain circumstances, such as to promote important public policy goals. *See, e.g., Transource Wisconsin, LLC*, 149 FERC ¶ 61,180, at PP 16, 19 (2014)), finding that UI had not demonstrated that the circumstances under which such action could be taken (e.g. to promote important public policy goals) were present in this case.

[32] "State Parties" are: the MA AG, CT AG, CT DEEP, CT PURA, and the CT OCC.

[33] *UI Pequonnock Rate Incentive Order* at PP 63-64.

[34] Citing prior FERC precedent where the FERC previously allowed Public Citizen to cure a deficient motion to intervene in an answer by stating its members' interest in the proceedings and public interest role. *See Southwest Airlines Co. v. Colonial Pipeline Co.*, 166 FERC ¶ 61,094, at PP 10, 16 (2019).

2019. On June 14, 2019, UI requested rehearing of the *UI Pequonnock Rate Incentive Order*, focused specifically on the FERC's denial of the request for an ROE Incentive Adder. UI's request is pending, with FERC action required on or before July 15, 2019, or the request will be deemed denied by operation of law. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **VTransco Tax Rate Attachment F Waiver Request (ER19-1832)**

On May 13, VTransco filed for a one-time waiver of certain provisions of ISO-NE OATT Attachment F to permit VTransco to reflect a 21% federal income tax rate in its 2019 projected transmission revenue requirement for the Regional Network Service ("RNS") rate. Absent the requested waiver, Attachment F would require VTransco to use its 2018 federal tax rate (which was 23.5%) to calculate its 2019 RNS rate. VTransco's 2019 federal income tax rate is 21%. Rather than use the higher rate, over-collect, and subsequently refund that over-collection, VTransco requested the waiver to avoid those extra steps and provide ratepayers the immediate benefit of the lower rate. An expedited seven-day comment date was requested and granted. No comments were filed. On June 11, the FERC granted the waiver request, effective June 1, 2019.[35] Unless the *VTransco Waiver Order* is challenged, this proceeding will be concluded. If there are any questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **FCA13 Results Filing (ER19-1166)**

On March 1, ISO-NE filed the results of the thirteenth FCA ("FCA13") held February 4, 2019. ISO-NE reported the following highlights:

- FCA13 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) and the Rest-of-Pool Capacity Zone (the Connecticut and Western/Central Massachusetts Load Zones).
- FCA13 commenced with a starting price of $13.050/kW-mo. and concluded for the SENE, NNE and Rest-of-Pool after four rounds.
- Resources will be paid as follows:
  - $3.800/kW-mo. – all Capacity Zones
  - $3.800/kW-mo. – NY AC Ties imports (522 MW) and Highgate (57 MW)
  - $3.800/kW-mo. – Phase I/II HQ Excess external interface (431 MW)
  - $2.681/kW-mo. – New Brunswick imports (184 MW).
- The substitution auction resulted in a single clearing price of $0.000 for all Capacity Zones. No demand bids cleared that were priced below the substitution auction clearing price.
- No resources cleared as Conditional Qualified New Generating Capacity Resources.
- No Long Lead Time Generating Facilities secured a Queue Position to participate as a New Generating Capacity Resource.
- No de-list bids were rejected for reliability reasons.

ISO-NE asked the FERC to accept the FCA13 rates and results, effective June 28, 2019. Comments on this filing were due on or before April 12, 2019.

Protests to the FCA13 Results filing were filed by ***Capacity Suppliers*** (concerned that the IMM failed to properly apply the procedures and standards for setting below-ORTP offer floors, particularly for the Killingly

[35] *Vermont Transco LLC*, 167 FERC ¶ 61,216 (June 11, 2019) ("*VTransco Waiver Order*").

Energy Center ("Killingly")),[36] ***MA AG*** (suggesting the justness and reasonableness of the rates were open to question due to Vineyard Wind's inability to participate in FCA13 under the RTR exemption because the FERC failed to act on Vineyard Wind's Petition for Waiver in ER19-570), ***Vineyard Wind*** (similarly asserting that its preclusion from participation as an RTR caused the results to be not just and reasonable, unduly discriminatory and preferential), and ***Public Citizen*** (suggesting the FCA13 results are unjust and unreasonable because of the FERC's failure to act on the Vineyard Wind waiver request, the FERC's failure to take action in response to the EE M&V Declaratory Order Petition, and the failure of CASPR to deliver lower-priced capacity for New England ratepayers). ***NEGPA*** and ***Calpine*** submitted comments (neither specifically challenging the FCA13 results, but NEPGA asking the FERC find the FCA13 Results Filing deficient in that it did not include testimony from the IMM explaining the impact, if any, ISO-NE's administrative actions had on the competitiveness of the FCA13 results, and Calpine identifying a concern that the results suggest there is a systemic problem with the FCM rules, including the financial assurance requirements applicable to new resources). NEPOOL, Avangrid Renewables, Calpine, Dominion, Dynegy/Vistra, Eversource, Exelon, FirstLight, National Grid, NESCOE, NextEra, PSEG, CT AG, CT OCC, CT DEEP, EPSA, Helix Maine Wind Development, Sierra Club, and Public Citizen have filed doc-less interventions. On April 29, ISO-NE and the ISO-NE IMM filed answers to the protests and comments submitted. On May 7, Vineyard Wind answered ISO-NE's April 29 answer. On May 10, Clean Energy Advocates[37] answered Vineyard Wind's May 7 answer and other comments submitted in the proceeding. Answers and additional comments were also subsequently filed by Mitsubishi Hitachi Power Systems Americas ("MHPS") (responding specifically to certain statements made about MHPS's turbine technology in the Niemann Affidavit and corresponding statements in Capacity Suppliers' comments) NEPGA and Capacity Suppliers (each answering ISO-NE and the IMM's answers).

Supplement Regarding Failure to Publish Disaggregated Quantity Information. On May 24, ISO-NE submitted supplemental information for the record. In that submission, ISO-NE indicated that, contrary to its Tariff requirements, the auction software used to conduct FCA13 did not publish the disaggregated quantity of capacity from Demand Capacity Resources by type at the End-of-Round Price for each Capacity Zone ("Disaggregated Quantity Information") during FCA 13.[38] ISO-NE stated that the Disaggregated Quantity Information publication requirement was instituted with the original FCM construct to provide capacity suppliers with active demand resources (i.e., Real-Time Demand Resources ("RTDR") and Real-Time Emergency Generation ("RTEG")) with data to help inform their continued participation in a FCA. With the June 1, 2018 removal of RTDR and RTEG as demand resource types, ISO-NE stated that "there appears to be no rationale for posting" Disaggregated Quantity Information, but acknowledged that the Tariff language had not been removed. ISO-NE hypothesized that "that the omission of the information [during FCA13] had no effect on the auction outcome and that no Market Participant incurred financial harm from the omission of the information." ISO-NE stated that it intends, following discussion with NEPOOL, to make a filing deleting from the Tariff the Disaggregated Quantity Information publication requirement. ISO-NE asked the FERC to accept the FCA13 filing, as supplemented.

June 6, 2019 Deficiency Letter. On June 6, the FERC issued a deficiency letter indicating that the filing did not provide sufficient detail to enable the FERC to process the filing. The letter directed ISO-NE to submit specified information regarding the bid and review of the bid received from Killingly. ISO-NE's responses to the questions are due on or before July 8, 2019. ISO-NE's responses will constitute an amendment to its filing, will be publicly noticed for an additional comment period, and will re-set the date by which the FERC must statutorily take action on this filing.

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[36] "Capacity Suppliers" for purposes of this proceeding are: Great River Hydro, NRG Power Marketing, Cogentrix Energy Power Management, and Vistra Energy Corp.

[37] "Clean Energy Advocates" are Sierra Club, CLF and Acadia Center.

[38] Tariff Sections III.13.2.3.3(a), (b) and (c) require (in a non-final round) that the "auctioneer shall publish the quantity of capacity in the Capacity Zone from Demand Capacity Resources by type at the End-of-Round Price".

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

As previously reported, on December 20, 2018, in a 2-1 decision (Commissioner Glick dissenting; Commissioner McIntyre not voting; Commissioner McNamee not participating), which followed an evidentiary proceeding and two rounds of briefing, the FERC conditionally accepted the Cost-of-Service Agreement ("COS Agreement")[39] among Constellation Mystic Power ("Mystic"), Exelon Generation Company ("ExGen") and ISO-NE.[40] The COS Agreement will provide compensation for the continued operation of the Mystic 8 & 9 units from June 1, 2022 through May 31, 2024. The *Mystic Order* directed Mystic to submit a compliance filing (intended to modify aspects of the COS Agreement that FERC rejected or directed be changed) on or before February 18, 2019, and established a paper hearing to ascertain whether and how the ROE methodology that FERC proposed in *Coakley* should apply in the case. Initial briefs on the ROE issue are due on or before April 19, 2019, and reply briefs are due on or before July 18, 2019.[41] Requests for clarification and/or rehearing of the *Mystic Order* were filed by Constellation Mystic Power, CT Parties, EDF, ENECOS, MA AG, NESCOE, NextEra, and Repsol. On February 6, Constellation answered the other parties' requests for rehearing. CT Parties answered Constellation's request for rehearing on February 8. On February 14, NESCOE answered Constellation's February 6 answer. On February 15, the FERC issued a tolling order affording it additional time to consider the requests for clarification and/or rehearing, which remain pending.

Mystic's Compliance Filing. On March 1, following a 10-day extension of time granted on February 14, 2019, Mystic submitted its required compliance filing. The compliance filing included the following modifications:

- Modification to Section 2.2 (Termination) which provides ISO-NE will be required to seek FERC authorization to extend the term of the COS Agreement beyond May 31, 2024; deletion of Section 2.2.1 in its entirety;
- Inclusion of a clawback provision;
- Modification to Section 4.4 related to settlement of over- and underperformance credits;
- A clarification that fuel opportunity costs will not be included as part of the Stipulated Variable Costs used to calculate the revenue credits;
- Modifications to information access provisions (§ 6.2) both to allow ISO-NE full access to information and to support verification of third-party sales;
- Modifications to Schedule 3 supporting multiple compensation-related directives (e.g. cost of capital/cost of service, fuel supply charge, settlement of over- and under-performance credits);
- Schedule 3A modifications related to Mystic's true-up process; and
- Non-substantive conforming changes.

In addition, Mystic's compliance filing included for informational purposes changes to the Fuel Supply and Terminal Services Agreements. Comments on Mystic's compliance filing were due on or before March 22, 2019. Protests and comments were filed by CT Parties, ENECOS, MA AG, National Grid, Public Systems (MMWEC/NHEC),

[39] The COS Agreement, submitted on May 16, 2018, is between Mystic, Exelon Generation Company, LLC ("ExGen") and ISO-NE. The COS Agreement is to provide cost-of-service compensation to Mystic for continued operation of Mystic 8 & 9, which ISO-NE has requested be retained to ensure fuel security for the New England region, for the period of June 1, 2022 to May 31, 2024. The COS Agreement provides for recovery of Mystic's fixed and variable costs of operating Mystic 8 & 9 over the 2-year term of the Agreement, which is based on the pro forma cost-of-service agreement contained in Appendix I to Market Rule 1, modified and updated to address Mystic's unique circumstances, including the value placed on continued sourcing of fuel from the Distrigas liquefied natural gas ("LNG") facility, and on the continued provision of surplus LNG from Distrigas to third parties.

[40] *Constellation Mystic Power, LLC*, 165 FERC ¶ 61,267 (Dec. 20, 2018) ("*Mystic Order*").

[41] *Id.* at PP 31-34.

and NESCOE. Mystic answered the March 22 protests on April 8. Also, on March 22, Concord, Reading and Wellesley moved for the release from Protective Order a documentary response regarding the net book value of Mystic 8 and 9 from the 2006 Mystic 8/9 RMR proceeding (ER06-427). Mystic's compliance filing and the pleadings related thereto are pending before the FERC.

ROE Paper Hearing. The *Mystic Order* established a paper hearing to determine the just and reasonable ROE to be used in setting charges under Mystic's COS Agreement. On April 19, Mystic, Connecticut Parties, ENECOS, MA AG, and FERC Trial Staff filed initial briefs.

July Mystic COS Agreement Order. Rehearing remains pending of the FERC's July order. As previously reported, the FERC issued an initial order regarding the COS Agreement, accepting the COS Agreement but suspending its effectiveness and setting it for accelerated hearings and settlement discussions.[42] The *Mystic COS Agreement Order* was approved by a 3-2 vote, with dissents by Commissioners Powelson and Glick. Challenges to the *July Mystic COS Agreement Order* were filed by NESCOE, ENECOS, MA AG, and the NH PUC. Constellation answered the NESCOE request for reconsideration on August 21. On September 10, 2018, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending.

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

- **MPD OATT 2019 Annual Informational Filing (ER15-1429-000)**

On May 1, 2019, as corrected by its filing on May 16, 2019, Emera Maine submitted its annual informational filing setting forth, for the June 1, 2019 to May 31, 2020 rate year, the charges for transmission service under the MPD OATT ("MPD Charges") and an updated transmission real power loss factor. Although this filing and the May 16 correction will not be noticed for public comment, it will be subject to the process established in the "Protocols for Implementing and Reviewing Charges Established by the MPD OATT Attachment J Rate Formulas" and may result in further proceedings (*see, e.g.*, ER15-1429-010 below). On June 11, Maine Customer Group ("MCG") moved to strike a portion of Emera Maine's May 1 compliance filing. Specifically, MCG moved to strike the trueup to actuals portion of Emera's Annual Update filing to the extent that true-up proposes a change in the formula rate from a direct assignment of Maine Public District ("MPD") post- retirement benefits other than pensions ("PBOPs") to an allocation of company-wide PBOPs (which MCG argued would be a retroactive change to Emera Maine's formula rate, otherwise required to effect only prospectively). If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **MPD OATT 2018 Annual Informational Filing (ER15-1429-010)**

On April 30, 2019, the FERC granted, in part, the formal challenge filed on December 31, 2018 by the Maine Customer Group[43] (the "2018 Challenge") to Emera Maine's May 15, 2018 annual informational filing[44]and set the remaining issues for hearing and settlement judge procedures.[45] As previously reported, the 2018 Challenge sought certain cost reductions/ exclusions[46] to be effective June 1, 2018 following

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[42] *Constellation Mystic Power,* 164 FERC ¶ 61,022 (July 13, 2018) ("*July Mystic COS Agreement Order*"), *reh'g requested*.

[43] For purposes of this proceeding, "Maine Customer Group" or "MCG" is the MPUC, MOPA, Houlton Water Co., and Van Buren Light & Power District, and Eastern Maine Electric Cooperative.

[44] The May 15 filing, submitted in accordance with the Protocols for Implementing and Reviewing Charges Established by the MPD OATT Attachment J Rate Formulas ("Protocols"), set forth for the June 1, 2018 to May 31, 2019 rate year, the charges for transmission service under the MPD OATT ("MPD Charges"). *See* May 31, 2018 Litigation Report.

[45] *Emera Maine*, 167 FERC ¶ 61,090 (Apr. 30, 2019) ("*2018 Challenge Order*").

[46] The formal challenge sought (i) exclusion of certain regulatory expenses allocated or directly assigned to the MPD transmission customers; (ii) exclusion of costs that would otherwise constitute a double-recovery for amortization of losses incurred as a result of a

unsuccessful efforts to obtain the relief sought directly from Emera Maine MPD through informal resolution procedures in accordance with the Protocols. In granting in part the 2018 Challenge, the FERC found that Emera Maine's formula rate should be corrected for the current rate year and Emera Maine must submit a compliance filing on or before May 30 that revises its 2018-2019 formula rate charges to correct certain acknowledged errors, exclusion of certain costs for land associated with a project not in service, the exclusion of certain costs for distribution equipment from transmission rates, and the flowback of excess ADIT. As to the remaining issues, addressing Administrative and General ("A&G") expenses, merger-related prior losses, exclusion of costs attributed to Line 6901, and exclusion of land rights cost, the FERC found that the 2018 Annual Update raises issues of material fact that cannot be resolved based on the record and set those issues for hearing and settlement judge procedures. Hearings will be held in abeyance to provide time for settlement judge procedures.

Settlement Judge Procedures. On May 7, Chief Judge Cintron designated John P. Dring as the Settlement Judge for these proceedings. On May 20, Judge Dring scheduled a settlement conference for July 18, 2019.

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

- **MPD OATT 2018 Annual Info Compliance Filing (ER15-1429-011)**

On May 16, 2019, Emera Maine submitted a filing in response to the requirements of the *2018 Challenge Order* that revises the MPD 2018-19 formula rate charges to correct three errors raised by Maine Customer Group ("MCG"). Emera Maine stated that it calculated refunds due to wholesale (both network and point-to-point) customers as a result of these corrections and will issue such refunds, with interest, to those customers by May 31, 2019. As for the $46,095 plus interest refund to retail customers, Emera Maine asked for a waiver of the need to issue direct refunds to each of its retail customers and in lieu of such direct refunds, reduced the retail annual transmission revenue requirement for 2019-2020. With respect to excess accumulated deferred income tax ("ADIT") issues, Emera Maine stated that no changes or adjustments were needed to charges levied under the MPD OATT for the June 1, 2018 to May 31, 2019 rate year. On May 22, MCG protested the compliance filing for Emera Maine's failure to provide for flowback to customers of excess ADIT effective June 1, 2018. MCG requested that the FERC order Emera to adjust and re-file its Compliance Filing so as to effectuate what it described as "the Commission's clear mandate that flowback of excess ADIT should be made effective June 1, 2018." On June 7, Emera Maine answered MCG's May 22 protest. MCG submitted a brief reply to that answer on June 14. This matter is pending before the FERC.

- **TOs' *Opinion 531-A* Compliance Filing Undo (ER15-414)**

Rehearing remains pending of the FERC's October 6, 2017 order rejecting the TOs' June 5, 2017 filing in this proceeding.[47] As previously reported, the June 5 filing was designed to reinstate TOs' transmission rates to those in place prior to the FERC's orders later vacated by the DC Circuit's *Emera Maine*[48] decision. In its *Order Rejecting Filing*, the FERC required the TOs to continue collecting their ROEs currently on file, subject to a future FERC order.[49] The FERC explained that it will "order such refunds or surcharges as necessary to replace the rates set in the now-vacated order with the rates that the Commission ultimately determines to be

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merger; (iii) correction of MPD-acknowledged errors in its Annual Update Filing; (iv) exclusion of certain costs for land associated with a project not in service; (v) exclusion from transmission rates certain costs for distribution equipment; (vi) exclude of costs improperly attributed to line 6901; and (vii) a flowback of excess ADIT resulting from the corporate tax reduction, and a requirement for Emera MPD to include a worksheet in its tariff to track excess/deficient ADIT.

[47] *ISO New England Inc.*, 161 FERC ¶ 61,031 (Oct. 6, 2017) ("*Order Rejecting Filing*"), *reh'g requested*.

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

[49] *Order Rejecting Filing* at P 1.

just and reasonable in its order on remand" so as to "put the parties in the position that they would have been in but for [its] error." For the time being, so as not to "significantly complicate the process of putting into effect whatever ROEs the Commission establishes on remand" or create "unnecessary and detrimental variability in rates," the FERC has temporarily left in place the ROEs set in *Opinion 531-A*, pending an order on remand.[50] On November 6, the TOs requested rehearing of the *Order Rejecting Filing*. On December 4, 2017, the FERC issued a tolling order providing it additional time to consider the TOs' request for rehearing of the *Order Rejecting Filing*, which remains pending. If you have any questions concerning this matter, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

- **DAM Offer Cap Changes (ER19-2137)**

On June 14, ISO-NE and NEPOOL jointly filed Tariff changes to revise the dispatch treatment of resources whose Supply Offers are price-capped in the Day-Ahead Energy Market ("DAM"), to become effective March 1, 2020. In addition, ISO-NE further proposed to move the effective date for all of the *Order 831* Offer Cap revisions, including those previously accepted, from October 1, 2019 to March 1, 2020. The DAM Offer Cap Changes were supported by the Participants Committee at its May 3 meeting (Consent Agenda Item # 2). Comments on this filing are due on or before July 5, 2019. Thus far, doc-less interventions have been filed by Eversource, Exelon and National Grid. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Waiver Request: FCA14 SOI Deadline (New Brunswick Energy Mktg) (ER19-2011)**

On May 30, New Brunswick Energy Marketing ("NB"), which is hoping to qualify an import capacity resource using Control Area-backed generation, requested a limited waiver of the FCA14 qualification schedule to allow ISO-NE to accept NB's Show of Interest ("SOI") form after the relevant SOI deadline established for FCA14. Comments on NB's waiver request were due on or before June 13, 2019. NEPOOL and NRG filed doc-less interventions, but no comments or oppositions were filed. On June 20, finding NB had met its waiver criteria, and noting that no parties opposed the NB request, the FERC granted the requested waiver, allowing NB to proceed in the qualification process.[51] Unless the June 20 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **ISO-NE's Interim Winter Energy Security (Chapter 2B) Proposal (ER19-1428)**

On March 25, ISO-NE filed its "Inventoried Energy Program" (a/k/a its "Chapter 2B Proposal") for the Winters of 2023-2024 and 2024-2025 (FCA14 and FCA15 Capacity Commitment Periods). ISO-NE stated that the "program will provide incremental compensation to resources that maintain inventoried energy during cold periods when winter energy security is most stressed" and "fulfills a commitment … to identify an interim solution that could complement efforts currently underway to develop a long-term, market-based solution to the region's energy security challenges." A May 28, 2019 effective date was requested. The changes were not supported by the Participants Committee when considered at its March 13 meeting. The ISO-NE Chapter 2B Proposal received a NEPOOL Vote of 32.67% in favor. Comments on this filing were due on or before April 15, 2019. Doc-less interventions were filed by NEPOOL, Avangrid, Calpine, ConEd, CT DEEP, CT OCC, Dominion, Energy New England ("ENE"), Eversource, Exelon, HQ US, LS Power (through Ocean State Power and Wallingford Energy), MA AG, MA DPU, NESCOE, NRG, Shell, Verso, American Petroleum Institute ("API"), EPSA, NH PUC, RENEW, Public Citizen, and Sierra Club.

[50] *Id.* at P 36.

[51] *New Brunswick Energy Mktg. Corp.*, 167 FERC ¶ 61,252 (June 20, 2019).

On April 8, the IMM submitted comments which it stated were "focused on aspects related to administering the Tariff's mitigation rules in both the energy and capacity markets in light of the expected net revenue streams available to resources that elect to participate in the interim program, and on the timing for calculating the administratively-determined forward and spot prices. The IMM comments included the following suggestions:

- Energy market bids of resources that forego revenues from the interim program by converting inventoried energy into electric power should be subject to adjustment/mitigation to reflect such opportunity costs in their Supply Offers at the spot rate for inventoried energy
- Inclusion of opportunity costs of the interim program into energy market bids of participating energy-secure resources likely will impact the wholesale energy markets and result in (a) preserving energy-secure resources for when they are most valuable; (b) a reduced (or eliminated) need for manual intervention in dispatch to preserve fuel-secure resources until needed (so-called resource posturing which can result in price distortions); and (c) an increase in Day-Ahead and Real-Time energy market prices (i.e., LMPs) that directly reflect the value of the scarce fuel-secure energy.
- To the extent that a Participant expects to accrue positive net revenue from the interim program, a competitive De-List bid and New Supply Offer in the FCA would account for this positive revenue stream in the calculation of the resource's net Going Forward Costs, just like any ancillary service revenue, and result in a lower priced bid or offer to better reflect a competitive price to obtain a CSO.
- Failure to account for interim revenue in FCM mitigation potentially could result in the non-economic retirements of energy-secure resources as a result of higher, non-competitively priced bids.
- ISO-NE should factor into its interim proposal a mechanism for recalculating the forward and/or spot rates for inventoried energy closer to the time of procurement of fuel and delivery of inventoried capacity beginning in December 2023, in order to better ensure consistency with the cost of providing winter energy security.

Also on April 8, NRG Power Marketing LLC ("NRG") and Cogentrix Energy Power Management, LLC requested a 15-day extension of time, to April 30, 2019, to submit comments in response to the Chapter 2B Proposal Filing. The FERC denied that request on April 12.

Comments and protests on the Chapter 2B Proposal Filing were filed by: NEPOOL, Algonquin Gas Transmission, Brookfield, Calpine/Vistra, Exelon, MA AG, MPUC, NECOS/ENE/Direct, NEPGA, NRG, Repsol, Verso, API/NGSA/IPAA, Clean Energy Advocates, NH PUC/NH OCA, V DPS, VT DPU, and Public Citizen. Answers were filed by NEPOOL, ISO-NE and the IMM. On May 14, the MA AG answered ISO-NE's April 20 answer.

May 8 Deficiency Letter & ISO-NE Response (ER19-1428-001). On May 8, the FERC issued a deficiency letter requesting additional information in order to process ISO-NE's Chapter 2B Proposal. ISO-NE submitted its response and additional information in response to the deficiency letter on June 6, 2019. Comments on the ISO-NE responses are due on or before June 27, 2019.

If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Jamie Blackburn (202-218-3905; jblackburn@daypitney.com).

- **ISO-NE eTariff Versioning Corrections (ER19-1387)**

On May 3, the FERC accepted updates to ISO-NE's Tariff that ISO-NE filed to ensure that its eTariff properly reflects the effective Tariff versioning.[52] No changes were made to accepted language or to previously accepted effective dates. Rather, the Tariff sheets were submitted simply to conform the eTariff versioning, correcting inaccuracies due to administrative oversight and assorted mismatches of filing and effective dates. The updates were accepted effective as of April 1, 2019 as requested. The May 3 order was not challenged, is final and unappealable, and this proceeding is now concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

Vineyard Wind's December 14, 2018 petition for a waiver of the ISO-NE Tariff provisions necessary to allow Vineyard Wind to participate in FCA13 as a Renewable Technology Resource ("RTR") remains pending. As previously reported, Vineyard Wind's request for RTR designation was earlier rejected by ISO-NE on the basis that the resource is to be located in federal waters. Under the CASPR Conforming Changes, Vineyard Wind would not have been precluded from utilizing the RTR exemption. Consistent with the discussion in the CASPR Conforming Changes filing, Vineyard Wind asked that the proration requirement that would be triggered by Vineyard Wind's participation in FCA13 as an RTR be limited for FCA13 to it and any other similarly situated entities (i.e. new offshore wind resources located in federal waters seeking RTR treatment); there would be no impact on resources currently qualified to use the RTR exemption in FCA13. Comments on Vineyard Wind's request were due on or before January 4, 2019. ISO-NE filed comments not opposing the Waiver Request, but requesting FERC action by January 29, 2019 if the waiver is to be effective for FCA13. NEPGA protested the Waiver Request. Answers to NEPGA's protest were filed by Vineyard Wind and NESCOE. On January 15, the Massachusetts Department of Energy Resources ("MA DOER") intervened out-of-time and submitted comments supporting the Waiver Request. Doc-less interventions were filed by NEPOOL, Avangrid, Dominion, ENE, National Grid, and NextEra.

On January 31, Vineyard Wind requested the immediate issuance of order on its request. Massachusetts Governor Baker submitted a request on February 1 that the FERC grant Vineyard Wind's waiver request that day. Also on February 1, ISO-NE reported at the Participants Committee meeting, and confirmed later that evening that, in the absence of a FERC order issued early that afternoon, it would proceed to run the auction without granting Vineyard Wind's MWs treatment under the RTR exemption. Early on February 4, Vineyard Wind submitted an emergency motion for immediate stay of FCA13 or, in the alternative, a requirement that FCA13 be re-run following FERC action. The FERC took no action ahead of FCA13 and FCA13 was run without Vineyard Wind receiving RTR treatment. Following FCA13, answers opposing Vineyard Wind's emergency motion were submitted by ISO-NE and NEPGA. A joint statement addressing the FERC's failure to act was issued by Commissioners LaFleur and Glick (to which Chairman Chatterjee responded via Twitter). The Massachusetts Attorney General filed a statement addressing the FERC's failure to act on February 13. On February 15, ISO-NE submitted a letter that addressed two concerns raised in Commissioner Glick's dissent from the *CASPR Conforming Changes Order.* On February 19, Vineyard Wind answered the NEPGA and ISO-NE protests to its motion to vacate and re-run FCA13 upon FERC approval of the waiver sought.

As noted, this matter remains pending before the FERC, with no activity since the last Report. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

[52] *ISO New England Inc.*, Docket No. ER19-1387 (May 3, 2019) (unpublished letter order).

- ***Order 841* Compliance Filing (ER19-470)**

On December 3, 2018, ISO-NE and NEPOOL jointly filed changes to Market Rule 1 and the OATT (and the PTO AC joined in the filing of the OATT revisions) in response to the requirements of *Order 841*.[53] For the majority of the revisions, ISO-NE requested a December 3, 2019 effective date; for a limited number of revisions, ISO-NE requested a January 1, 2024 effective date. The *Order 841* compliance changes were supported by the Participants Committee at its November 2, 2018 meeting. Following a request for a 45-day extension of time,[54] comments on this filing were due February 7, 2019. Doc-less interventions were filed by Exelon, LS Power, NESCOE, APPA, EPSA, NRECA, GlidePath Development, Lincoln Clean Energy, and Voith Hydro. Protests and comments were filed by Calpine, EDF Renewables, RENEW Northeast ("RENEW"), AEE, ESA, and Tesla. On February 22, NEPOOL, ISO-NE and NRECA filed answers to the comments and protests. On March 1, Voith Hydro submitted comments regarding advanced pumped storage hydro technology. On March 21, ESA filed an answer to ISO-NE's February 22 answer (requesting that the FERC require the issues with the redeclaration process to be resolved prior to December 3, 2019 implementation deadline).

ISO-NE Response to FERC Request for Additional Information (ER19-470-001). As previously reported, on April 1, 2019, the FERC issued a letter advising that additional information was necessary to process the compliance filing and directing that responses to the questions posed in the letter order be submitted on or before May 1, 2019. ISO-NE filed additional information and Tariff changes in response to that letter order on May 1, 2019. The Tariff changes included in the ISO-NE March 1 response were supported by the Participants Committee at its May 3 meeting (Agenda Item #7). Comments on the ISO-NE responses were due on or before May 22, 2019 and were filed by ***NEPOOL*** (reporting that, while it did not vote on the May 1 responses themselves, it did unanimously support the clarifying changes to the ISO-NE Tariff, and requesting that the FERC approve those changes and allow any additional implementation details to be worked through the Participants Processes) and ***AEE*** (which, reiterating its initial comments, stated that ISO-NE did not demonstrate that its metering and accounting practices will ensure that all energy storage resources ("ESR") can participate in the New England Markets and not be subject to inaccurate charges. AEE also challenged ISO-NE's limitation of ESR aggregations to a single point of interconnection).

This matter is again before the FERC. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

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

Requests for rehearing and/or clarification of the *Fuel Security Retention Proposal Order*[55] remain pending before the FERC. As previously reported, the *Fuel Security Retention Proposal Order* accepted ISO-NE's Proposal[56]

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

[54] The request for an extension of the previously noticed Dec. 24 comment deadline was requested by the Energy Storage Association ("ESA") and by a group comprised of Advanced Energy Economy ("AEE"), American Wind Energy Association ("AWEA"), Solar Energy Industries Association ("SEIA"), Solar RTO Coalition, and The Wind Coalition. The request was supported by the Acadia Center, NRDC, UCS, and the Sierra Club Environmental Law Program ("Public Interest Organizations").

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

[56] As previously reported, ISO-NE filed, in response to the *Mystic Waiver Order*, "interim Tariff revisions that provide for the filing of a short-term, cost-of-service agreement to address demonstrated fuel security concerns". ISO-NE proposed three sets of provisions to

in all respects, despite the various protests and alternative proposals filed. There was a concurring decision from Commissioner Glick, and a partial dissent from Chairman Chatterjee on the FCA price treatment issue. Challenges to the *Fuel Security Retention Proposal Order* were filed by NEPGA, NRG, Verso, Vistra/Dynegy Marketing & Trade, MPUC, and PIOs.[57] On February 1, 2019, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending. If you have further questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Economic Life Determination Revisions (ER18-1770)**

Rehearing of the FERC's November 9 order,[58] accepting the revised Tariff language that changed the determination of economic life under Section III.13.1.2.3.2.1.2.C of the Tariff, remains pending before the FERC. As previously reported, the Economic Life Revisions provide that the economic life of an Existing Capacity Resource is calculated as the evaluation period in which the net present value of the resource's expected future profit is maximized. The Economic Life Revisions were accepted effective as of August 10, 2018, as requested. In accepting the revisions, the FERC found that "it is just and reasonable to consider as part of the Economic Life calculation that a rational resource, in exercising competitive bidding behavior, would seek to exit the market, or retire, before it starts incurring consecutive losses."[59] The FERC found, contrary to NEPGA's assertions, that the "Economic Life Revisions do not represent a violation of the filed rate doctrine or constitute retroactive ratemaking."[60] Further, while the FERC was "mindful of the importance of not disrupting settled expectations based on existing market rules," the FERC concluded "that under these specific facts, the benefits of the proposed Economic Life Revisions outweigh potential disruptions to market participants' settled expectations and harm caused by reliance on the existing FCM rules."[61] On December 10, 2018, NEPGA requested rehearing of the *Economic Life Determination Revisions Order*. On January 8, 2019, the FERC issued a tolling order affording it additional time to consider NEPGA's request for rehearing, which remains pending. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

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

On July 2, 2018, the FERC issued an order[62] that (i) denied ISO-NE's request for waiver of certain Tariff provisions that would have permitted ISO-NE to retain Mystic 8 & 9 for fuel security purposes (ER18-1509); and (ii) instituted an FPA Section 206 proceeding (EL18-182) (having preliminarily found that the ISO-NE Tariff may be unjust and unreasonable in that it fails to address specific regional fuel security concerns identified in the record that could result in reliability violations as soon as year 2022). The *Mystic Waiver Order* required ISO-NE, on or before August 31, 2018 to either: (a) submit interim Tariff revisions that provide for the filing of a short-term, cost-

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

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

[58] *ISO New England Inc. and New England Power Pool Participants Comm.*, 165 FERC ¶ 61,088 (Nov. 9, 2018) ("*Economic Life Determination Revisions Order*").

[59] *Economic Life Determination Revisions Order* at P 23.

[60] *Id.* at P 24.

[61] *Id.* at P 27.

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

of-service agreement (COS Agreement) to address demonstrated fuel security concerns (and to submit by July 1, 2019 permanent Tariff revisions reflecting improvements to its market design to better address regional fuel security concerns "Chapter 3 Proposal"); or (b) show cause as to why the Tariff remains just and reasonable in the short- and long-term such that one or both of Tariff revisions filings is not necessary.

Addressing the waiver element, the FERC found the waiver request "an inappropriate vehicle for allowing Mystic 8 and 9 to submit a [COS Agreement] in response to the identified fuel security need" and further that the request "would not only suspend tariff provisions but also alter the existing conditions upon which a market participant could enter into a [COS Agreement] (for a transmission constraint that impacts reliability) and allow for an entirely new basis (for fuel security concerns that impact reliability) to enter into such an agreement." The FERC concluded that "[s]uch new processes may not be effectuated by a waiver of the ISO-NE Tariff; they must be filed as proposed tariff provisions under FPA section 205(d)."[63] Even if it were inclined to apply its waiver criteria, the FERC stated that it would still have denied the waiver request as "not sufficiently limited in scope."[64]

Although it denied the waiver request, the FERC was persuaded that the record supported "the conclusion that, due largely to fuel security concerns, the retirement of Mystic 8 and 9 may cause ISO-NE to violate NERC reliability criteria." Finding ISO-NE's methodology and assumptions in the Operational Fuel-Security Analysis ("OFSA") and Mystic Retirement Studies reasonable, the FERC directed the filing of both interim and permanent Tariff revisions to address fuel security concerns (or a filing showing why such revisions are not necessary).[65] The FERC directed ISO-NE to consider the possibility that a resource owner may need to decide, prior to receiving approval of a COS Agreement, whether to unconditionally retire, and provided examples of how to address that possibility.[66] The FERC also directed ISO-NE include with any proposed Tariff revisions a mechanism that addresses how cost-of-service-retained resources would be treated in the FCM[67] and an *ex ante* cost allocation proposal that appropriately identifies beneficiaries and adheres to FERC cost causation precedent.[68]

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

- ***NEPGA*** (requesting that the FERC grant clarification that it directed, or on rehearing direct, ISO-NE to adopt a mechanism that prohibits the re-pricing of Fuel Security Resources in the FCA at $0/kW-mo. or at any other uncompetitive offer price);
- ***Connecticut Parties***[69] (requesting that the FERC clarify that (i) the discussion in the *Mystic Waiver Order* of pricing treatment in the FCM for fuel security reliability resources is not a final determination nor is it intended to establish FERC policy; (ii) the FERC did not intend to prejudge whether entering those resources in the FCM as price takers would be just and reasonable; and (iii) that ISO-NE may confirm its submitted position that price taking treatment for these resources would, in fact, be a just and reasonable outcome. Failing such clarification, Connecticut Parties request rehearing, asserting that the record fails to support a determination that resources retained for reliability to address fuel security concerns must be entered into the FCM at a price greater than zero);

[63] *Id.* at P 47.

[64] *Id.* at P 48.

[65] *Id.* at P 55.

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

[67] *Id.* at P 57.

[68] *Id.* at P 58.

[69] "Connecticut Parties" are the Conn. Pub. Utils. Regulatory Authority ("CT PURA") and the Conn. Dept. of Energy and Environ. Protection ("CT DEEP").

- ***ENECOS*** (asserting that the *Mystic Waiver Order* (i) misplaces reliance on ISO-NE "assertions concerning 'fuel security,' which do not in fact establish a basis in evidence or logic for initiating" a Section 206(a) proceeding; (ii) impermissibly relies on extra-record material that the FERC did not actually review and that intervenors were afforded no meaningful opportunity to challenge; and (iii) speculation concerning potential future modifications to the FCM bidding rules as to retiring generation retained for fuel security misunderstands the problem it seeks to address, and prejudices the already truncated opportunities for stakeholder input in this proceeding), ENECOS suggest that the FERC should grant rehearing, vacate its show cause directive, strike its dictum concerning potential treatment of FCM bidding for retiring generation retained for "fuel security," and direct ISO-NE to proceed either in accordance with its Tariff or under FPA Section 205 to address, with appropriate evidentiary support, whatever concerns it believes to exist concerning "fuel security");
- ***MA AG*** (asserting that the decision to institute a Section 206 proceeding was insufficiently supported by sole reliance on highly contested OFSA and Mystic Retirement Studies; and the FERC should reconsider the timeline for the permanent tariff solution and set the deadline for implementation no later than February 2020);
- ***MPUC*** (challenging the Order's (i) adoption of ISO-NE's methodology and assumptions in the OFSA and Mystic Retirement Studies without undertaking any independent analysis; (ii) failure to address arguments and analysis challenging assumptions in the OFSA and Mystic Retirement Studies; (iii) failure to address the MPUC argument that the Mystic Retirement Studies adopted a completely new standard for determining a reliability problem three years in advance; (iv) unreasonably discounting of the ability of Pay-for-Performance to provide sufficient incentives to Market Participants to ensure their performance under stressed system conditions; and (v) failure to direct ISO-NE to undertake a Transmission Security Analysis consistent with the provisions in the Tariff);
- ***New England EDCs***[70] (requesting clarification that (i) the central purpose of ISO-NE's July 1, 2019 filing is to assure that New England adds needed new infrastructure to address the fuel supply shortfalls and associated threats to electric reliability that ISO-NE identified in its OFSA and (ii) that, in developing the July 1, 2019 filing, ISO-NE is to evaluate Tariff revisions (such as those the EDCs described in their request), through which ISO-NE customers would pay for the costs of natural gas pipeline capacity additions via rates under the ISO-NE Tariff);
- ***PIOs***[71] (asserting that (i) the FERC failed to respond to or provide a reasoned explanation for rejecting the arguments submitted by numerous parties that key assumptions underlying and the results of the ISO-NE analyses were flawed; and (ii) the FERC's determination that ISO-NE's analyses were reasonable is not supported by substantial evidence in the record); and
- ***AWEA/NGSA*** (asserting that the FERC erred (i) in finding that ISO-NE's OFSA and subsequent impact analysis of fuel security was reasonable without further examination and (ii) in its preliminary finding that a short-term out-of-market solution to keep Mystic 8 & 9 in operation is needed to address fuel security issues).

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

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

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

August 14/16 answers. On August 27, 2018, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending.

If you have any questions concerning this proceeding, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **CASPR (ER18-619)**

Rehearing of the FERC's order accepting and ISO-NE's Competitive Auctions with Sponsored Policy Resources ("CASPR") revisions,[72] summarized in more detail in prior Reports, remains pending. Those requests were filed by (i) ***NextEra/NRG*** *(which* challenged the RTR Exemption Phase Out); (ii) ***ENECOS***[73] (challenging the FERC's findings with respect to the definition of Sponsored Policy Resource and the allocation of CASPR side payment costs to municipal utilities); (iii) ***Clean Energy Advocates***[74] (which challenged the CASPR construct in its entirety, asserting that state-sponsored resources should not be subject to the MOPR); and (iv) ***Public Citizen*** (which also challenged the CASPR construct in its entirety and the *CASPR Order*'s failure to define "investor confidence"). On April 24, ISO-NE answered Clean Energy Advocates' answer. On May 7, 2018, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending. If you have any questions concerning this proceeding, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **CONE & ORTP Updates (ER17-795)**

Rehearing remains pending of the FERC's October 6, 2017 order accepting updated FCM CONE, Net CONE and ORTP values.[75] In accepting the changes, the FERC disagreed with the challenges to ISO-NE's choice of reference technology (gas-fired simple cycle combustion-turbine) and on-shore wind capacity factor (32%). The changes were accepted effective as of March 15, 2017, as requested. On November 6, NEPGA requested rehearing of the *CONE/ORTP Updates Order*. On December 4, 2017, the FERC issued a tolling order providing it additional time to consider NEPGA's request for rehearing of the *CONE/ORTP Updates Order*, which remains pending. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **2013/14 Winter Reliability Program Remand Proceeding (ER13-2266)**

Still pending before the FERC is ISO-NE's compliance filing in response to the FERC's August 8, 2016 remand order.[76] In the *2013/14 Winter Reliability Program Remand Order*, the FERC directed ISO-NE to request from Program participants the basis for their bids, including the process used to formulate the bids, and to file with the FERC a compilation of that information, an IMM analysis of that information, and ISO-NE's recommendation as to the reasonableness of the bids, so that the FERC can further consider the question of

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

[73] The Eastern New England Consumer-Owned Systems ("ENECOS") are: Braintree Electric Light Department, Georgetown Municipal Light Department, Groveland Electric Light Department, Littleton Electric Light & Water Department, Middleton Electric Light Department, Middleborough Gas & Electric Department, Norwood Light & Broadband Department, Pascoag (Rhode Island) Utility District, Rowley Municipal Lighting Plant, Taunton Municipal Lighting Plant, and Wallingford (Connecticut) Department of Public Utilities. Wellesley Municipal Light Plant, which intervened in this proceeding as one of the ENECOS, did not join in the ENECOS' request for rehearing.

[74] "Clean Energy Advocates" are, collectively the NRDC, Sierra Club, Sustainable FERC Project, CLF, and RENEW Northeast, Inc.

[75] *ISO New England Inc.*, 161 FERC ¶ 61, 035 (Oct. 6, 2017)("*CONE/ORTP Updates Order*"), *reh'g requested*.

[76] *ISO New England Inc.*, 156 FERC ¶ 61,097 (Aug. 8, 2016) ("*2013/14 Winter Reliability Program Remand Order*"). As previously reported, the DC Circuit remanded the FERC's decision in ER13-2266, agreeing with TransCanada that the record upon which the FERC relied is devoid of any evidence regarding how much of the 2013/14 Winter Reliability Program cost was attributable to profit and risk mark-up (without which the FERC could not properly assess whether the Program's rates were just and reasonable), and directing the FERC to either offer a reasoned justification for the order in ER13-2266 or revise its disposition to ensure that the Program rates are just and reasonable. *TransCanada Power Mktg. Ltd. v. FERC,* 2015 U.S. App. LEXIS 22304 (D.C. Cir. 2015).

whether the Bid Results were just and reasonable.[77] ISO-NE submitted its compliance filing on January 23, 2017, reporting the IMM's conclusion that "the auction was not structurally competitive and a 'small proportion' of the total cost of the program may be the result of the exercise of market power" but that the "vast majority of supply was offered at prices that appear reasonable and that, for a number of reasons, it is difficult to assess the impact of market power on cost." Based on the IMM and additional analysis, ISO-NE recommended that "there is insufficient demonstration of market power to warrant modification of program." In February 13 comments, both TransCanada and the MA AG protested ISO-NE's conclusion and recommendation that modification of the program was unwarranted. TransCanada requested that FERC establish a settlement proceeding where Market Participants could "exchange confidential information to determine what the rates should be" and refunds and "such other relief as may be warranted" provided. On February 28, ISO-NE answered the TransCanada and MA AG protests. On March 10, 2017, TransCanada answered ISO-NE's February 28 answer. This matter remains pending before the FERC. If you have any questions concerning these matters, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

IV. OATT Amendments / TOAs / Coordination Agreements

- **Interconnection Studies Scope and Reasonable Efforts Timelines Changes (ER19-1952)**

On May 22, 2019, ISO-NE, NEPOOL and the PTO AC together filed changes to Schedule 22 of the OATT to: (i) reduce the scope of the Interconnection Feasibility Study ("Feasibility Study") and increase the Reasonable Efforts timeframe for completing that study; and (ii) increase the Reasonable Efforts timeframe for completing the Interconnection System Impact Study ("SIS"). The Filing Parties asked that these changes become effective on the same date that the *Order 845* Changes (*see* ER19-1951 below) become effective. The *Order 845* compliance changes were supported by the Participants Committee at its May 3, 2019 meeting (Consent Agenda Item No. 4).

On May 31, AWEA requested a 21-day extension of time to submit comments in this proceeding (and the ISO-NE Order 845 Compliance Filing proceeding (ER19-1951 just below)). The FERC granted AWEA's request, in part, on June 7. Comments in these proceedings are now due June 26, 2019. Thus far, doc-less interventions have been filed by Avangrid, Calpine, Dominion, EDP, National Grid, and NRG. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Jamie Blackburn (202-218-3905; jblackburn@daypitney.com).

- ***ISO-NE Order 845* Compliance Filing (ER19-1951)**

On May 22, 2019, ISO-NE and the PTO AC ("Filing Parties") jointly filed proposed revisions to the Large Generator Interconnection Procedures ("LGIP") and Agreement ("LGIA") in Schedule 22 of the ISO-NE OATT in response to the requirements of *Order 845* ("ISO/TO Proposal"). The Filing Parties asserted that the ISO/TO Proposal "fully compl[ies] with the requirements in Order Nos. 845 and 845-A, and request that the Commission accept them as proposed herein, without modifications or conditions, effective upon issuance of its order accepting this filing." The ISO/TO Proposal did not include the RENEW Amendment's revisions to the Surplus Interconnection Service provisions supported by the Participants Committee at its May 3 meeting ("NEPOOL Proposal"). The Participants Committee considered but did not support the ISO/TO Proposal (without the RENEW Amendment) at its May 3 meeting.

On May 31, AWEA requested a 21-day extension of time to submit comments in this proceeding (and the Interconnection Studies Scope and Reasonable Efforts Timelines Changes proceeding (ER19-1952)). The FERC granted AWEA's request, in part, on June 7. Comments in these proceedings are now due June 26, 2019. Thus far, doc-less interventions have been filed by Avangrid, Calpine, Dominion, EDP, Eversource, MA AG, National Grid, NRG, and ESA. On June 5, NEPOOL submitted a protest. In its protest, NEPOOL urged the FERC to accept the ISO/TO Proposal to the extent it is consistent with the NEPOOL Proposal, and reject those

[77] *2013/14 Winter Reliability Program Remand Order* at P 17.

provisions for Surplus Interconnection Service that deviate both from the requirements of *Orders 845/845-A* and the NEPOOL Proposal. To the extent necessary or desirable, NEPOOL urged the FERC to direct ISO-NE to engage the NEPOOL stakeholder process to address any implementation concerns regarding Surplus Interconnection Service. NEPOOL went on to suggest that any additional provisions developed regarding such service that are properly considered rates, terms and conditions of service should be filed with the FERC and included in the ISO-NE Tariff. NEPOOL also urged the FERC to reject the PTOs' proposal for recovery of actual costs in the absence of a demonstration that their proposed deviation is consistent with or superior to the *Order 845* requirement for a negotiated and stated amount.

If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Jamie Blackburn (202-218-3905; jblackburn@daypitney.com).

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Changes

- **Schedule 21-UI: LCSA Cancellation - UI/EES5 (Bridgport Energy) (ER19-1921)**

On May 21, UI filed to cancel its Localized Costs Sharing Agreement ("LCSA") with Emera Energy Services Subsidiary No. 5 ("EES5") under Schedule 21-UI. The termination filing was made in light of the transfer of Category B Network Load Responsibility for the Bridgeport Energy facility to Revere Power LLC ("Revere Power"), which recently acquired the Bridgeport Energy facility (*see* ER19-1911 below). An April 1, 2019 effective date was requested. Comments on this filing were due on or before June 11; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-UI: LCSA - UI/Revere Power (Bridgeport Energy) (ER19-1911)**

Contemporaneously with its filing to cancel its LCSA with EES5, UI filed under Schedule 21-UI a LCSA by and between UI and Revere Power. UI filed the LCSA so that it can recover from Revere Power Bridgeport Energy's Category B Load Ratio Share of the revenue requirement for Bridgeport Energy's Localized Facilities under Schedule 21-UI. An April 1, 2019 effective date was requested. Comments on this filing were due on or before June 11; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-NEP: National Grid/Calpine Fore River RFA (ER19-1681)**

On June 18, the FERC accepted a Related Facilities Agreement ("RFA") between New England Power ("National Grid") and Calpine Fore River Energy Center, LLC ("Calpine Fore River") that addresses costs associated with National Grid's installation of high-speed relaying to accommodate stability issues, and protection upgrades at the Auburn St. Substation, in connection with Calpine Fore River's 726 MW generating facility. The RFA was accepted effective as of March 28, 2019, as requested. Unless the June 18 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-EM: BHD Excess ADIT Changes (ER19-1470)**

On March 29, 2019, Emera Maine filed additional changes to the Emera Maine, Bangor-Hydro District ("BHD") Formula Rate to ensure that excess ADITs are properly reflected in the calculations of charges under Schedule 21-EM (and thus inure to the benefit of customers). Comments on this filing were due on or before April 19, 2019. On April 19, the MPUC filed comments asserting the proposed changes lack transparency and recommending that this matter be accepted for filing, subject to refund, and set for hearing and settlement procedures. Emera Maine answered those comment on May 6. On May 28, pursuant to the May 24 Joint

Offer of Settlement filed in Docket No. ER15-1434-003 (see below), MPUC withdrew its April 19 comments. On May 8, Emera Maine filed corrections to typographical errors in the March 29 filing.

May 10 Deficiency Letter. On May 10, the FERC issued a deficiency letter requesting additional information in order to process Emera Maine's filing. Emera Maine submitted those responses on June 10, 2019. Comments on the deficiency letter responses are due on or before July 1. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-EM: MPD Excess ADIT Changes (ER19-1400)**

On March 21, 2019, Emera Maine filed additional changes to the Emera Maine, Maine Public District ("MPD") Formula Rate to ensure that excess ADITs are properly reflected in the calculations of charges under Schedule 21-EM (and thus inure to the benefit of customers). Comments on this filing were due on or before April 11, 2019. MPUC and Maine Customer Group filed protests on April 11, 2019. Emera Maine answered those protests on April 26.

Deficiency Letter. On May 10, the FERC also issued a deficiency letter in this proceeding requesting additional information in order to process Emera Maine's filing. Emera Maine submitted those responses on June 7, 2019. Comments on the deficiency letter responses are due on or before June 28. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-EM: 2018 Annual Update Settlement Agreement (ER15-1434-003)**

On May 24, Emera Maine submitted a joint offer of settlement between itself and the MPUC to resolve certain issues raised by the MPUC in response to Emera Maine's annual charges update filed, as previously reported, on June 15, 2018 (the "Emera 2018 Annual Update Settlement Agreement"). Under Part V of Attachment P-EM, "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 2018 Annual Update, a majority of which are resolved by the Emera 2018 Annual Update Settlement Agreement. Comments on the Emera 2018 Annual Update Settlement Agreement were due on or before June 14, 2019; none were filed. The Emera 2018 Annual Update Settlement Agreement is pending before the FERC. If you have any questions concerning these matters, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

The MPS Merger Cost Recovery Settlement, filed by Emera Maine on May 8, 2018 to resolve all issues pending before the FERC in the consolidated proceedings set for hearing in the *MPS Merger-Related Costs Order,*[78] and certified by Settlement Judge Dring[79] to the Commission,[80] remains pending before the FERC. As

[78] *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.

[79] 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.

previously reported, under the Settlement, permitted cost recovery over a period from June 1, 2018 to May 31, 2021 will be $390,000 under Attachment P-EM of the BHD OATT and $260,000 under the MPD OATT. If you have any questions concerning these matters, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-EM 2019 Annual Informational Filing (ER15-1434)**

On June 10, 2019, Emera Maine submitted its annual informational filing to update its local transmission service charges under Schedule 21-EM. Included in this filing was a populated version of Attachment P-EM that sets forth the rates that went into effect on June 1, 2019. The FERC will not notice this filing for public comment, and absent further activity, no further FERC action is expected. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-GMP Annual True Up Calculation Informational Filing (ER12-2304)**

On May 31, 2019, pursuant to Section 4 of Schedule 21-GMP, GMP submitted its annual informational filing containing the true-up calculation of its actual (rather than estimated) costs for the January 1, 2018 through December 31, 2018 time period. The FERC will not notice this filing for public comment, and absent further activity, no further FERC action is expected. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-VEC and 20-VEC Annual Informational Filing (ER10-1181)**

On April 30, 2019, VEC submitted its 16th annual update to the formula rates contained in Schedules 21-VEC and 20-VEC covering the July 1, 201 – June 30, 2020 period. VEC indicated that it was not proposing any changes to the underlying formulas. The FERC will not notice this filing for public comment, and absent further activity, no further FERC action is expected. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-NSTAR Annual Informational Filing (ER09-1243; ER07-549)**

On May 31, 2019, NSTAR submitted an informational filing containing the true-up of billings under Schedule 21-NSTAR for the period January 1, 2018 through December 31, 2018. NSTAR stated that the filing complies with the requirements of Section 4 and Attachment D of Schedule 21-NSTAR, as well as the Settlement Agreement approved previously by the FERC.[81] The FERC will not notice this filing for public comment, and absent further activity, no further FERC action is expected. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VII. NEPOOL Agreement/Participants Agreement Amendments

- **132nd Agreement (Press Membership Provisions) (ER18-2208)**

As previously reported, the FERC rejected, on January 30, 2019, the changes to the NEPOOL Agreement that would have precluded press reporters from becoming NEPOOL End User Participants or representatives of NEPOOL Participants.[82] In rejecting the changes, the FERC concluded that NEPOOL had not supported that "barring members of the press from exercising the privileges unique to NEPOOL membership—i.e. attending, speaking, and voting at NEPOOL meetings—will meaningfully advance its aim for candid deliberation in light of" NEPOOL's Bylaws and Standard Conditions Waivers & Reminders "currently in place—which this order does not affect—[that] already prohibit reporting on deliberations or attributing statements

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

[81] *See NSTAR Elec. Co.*, 123 FERC ¶ 61,270 at P 5 (2008).

[82] *New England Power Pool Participants Comm.*, 166 FERC ¶61,062 (Jan. 29, 2019) ("*Press Membership Provisions Order*"), *reh'g requested*. The rejected changes were identified in the One Hundred Thirty-Second Agreement Amending New England Power Pool Agreement ("132nd Agreement"), which was approved in balloting following the 2018 Summer Meeting.

to other NEPOOL members."[83] The FERC further indicated that the *Press Membership Provisions Order* only addressed NEPOOL's proposed changes to the NEPOOL Agreement, and not the pending RTO Insider Complaint (*see* EL18-196 above) that it addressed (and dismissed) in a separate order.

On February 28, 2019, NEPOOL requested clarification, or in the alternative rehearing, of the *Press Membership Provisions Order* (the "Request"). In the Request, NEPOOL asked the FERC, particularly in light of issues that remained pending in EL18-196, to clarify the extent to which the FERC sought to assert jurisdiction over the NEPOOL Agreement, or in the alternative, grant rehearing of the *Press Membership Provisions Order* on the grounds that it reflects an impermissible exercise of the FERC's jurisdiction. On March 4, Public Citizen submitted comments requesting that the FERC require NEPOOL to describe the notice and approval of its members sought in connection with the Request, insinuating that the request was unauthorized. On March 14 and 15, PIOs and RTO Insider responded to NEPOOL's Request, respectively. On March 28, the FERC issued a tolling order affording it additional time to consider NEPOOL's Request, which remains pending.

On May 1, 2019, NEPOOL submitted Michael Kuser's membership for FERC acceptance and that filing was accepted on June 18 (see ER19-1737 below). If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com), Dave Doot (860-275-0102; dtdoot@daypitney.com), or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

VIII. Regional Reports

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

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

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

The TOs' November 2, 2015 refund report documenting resettlements of regional transmission charges by ISO-NE in compliance with *Opinions No. 531-A*[84] *and 531-B*[85] also remains pending. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

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

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

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

- **Capital Projects Report - 2019 Q1 (ER19-1822)**

On May 10, 2019, ISO-NE filed its Capital Projects Report and Unamortized Cost Schedule covering the first quarter ("Q1") of calendar year 2019 (the "Report"). ISO-NE is required to file the Report under Section 205 of the FPA pursuant to Section IV.B.6.2 of the Tariff. Report highlights included the following new projects: (i) Balance of Planning Period ("BoPP") Financial Assurance Project ($889,800); (ii) External Website Portal and Infrastructure Upgrade ($879,100); (iii) Edge Network Redesign ($700,000); (iv) Baseline Telemetry System Improvements

[83] *Id.* at P 50.

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

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

($513,300); and (v) 2019 Issue Resolution Project ($430,000). Projects with a significant changes were (i) Winter Energy Security (2019 Budget decrease of $1.5 million, because of deadline extension, funds returned to Emerging Work Fund); (ii) Enterprise Application Integration Replacement (2019 Budget decrease of $1.15 million, for a total project cost of $640,000 – reduced because planning and development for project delayed); (iii) 2019 Issue Resolution Project Phase II (2019 Budget decrease of $750,000, funds returned to Emerging Work Fund); (iv) TranSMART Technical Architecture Update (2019 Budget decrease of $50,000, project deferred, funds returned to Emerging Work Fund); (v) IMM Data Analysis Phase II (budget decrease of $300,000 – projected hardware purchases no longer needed, funds returned to Emerging Work Fund); and (vi) Synchrophasor Initiatives – Next Generation (2019 Budget decrease of $100,000, contingency funds not needed, funds returned to Emerging Work Fund). Comments on this filing were due on or before May 31. NEPOOL filed comments on May 16 supporting the Q1 Report. Calpine, Eversource and National Grid filed doc-less interventions. On June 21, the FERC accepted the Report, effective April 1, 2019 as requested.[86] Unless the June 21 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).

- **IMM Quarterly Markets Reports – Winter 2019 (ZZ19-4)**

On May 7, 2019, the IMM filed with the FERC its Winter 2019 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 2019 Report was discussed with the Markets Committee at its May 7-8 meeting.

- **IMM 2018 Annual Markets Report (ZZ19-4)**

On May 24, the IMM filed its 2018 Annual Markets Report, which covers the 2018 calendar year period.[87] 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 2018. There were few periods in the Real-Time Energy Market when a relative shortage of energy and reserves resulted in scarcity pricing, and overall price-cost markups in the Day-Ahead Energy Market were within a reasonable range for a competitive market. There was an overall improvement in the structural competitiveness of the Real-Time Energy Market. There were fewer hours with pivotal suppliers in Real-Time. The number of energy market supply offers mitigated for market power remained very low. For the fifth consecutive year, the forward capacity auction procured surplus capacity, and clearing prices were the result of a competitive auction." Other highlights included:

  - 2018 Total wholesale costs ($12.1 billion) were $3 million higher than 2017, with 98% of the overall increase driven by energy and capacity market costs.
  - 2018 Energy costs totaled $6 billion, up $1.5 billion or 34% from 2017, with the increase driven by higher natural gas prices, which averaged $4.95/MMBtu, up 33% from 2017 prices.
  - Electricity demand in the third quarter of the year increased by 8%, or by 1,186 MW per hour, and drove a 2% year-over-year increase in demand. On a weather-normalized basis, demand was down slightly, continuing a longer-term downward trend due to the increase in utility-backed energy efficiency programs and behind-the-meter photovoltaic generation.

[86] *ISO New England Inc.*, Docket No. ER19-1822 June 21, 2019) (unpublished letter order).

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

In light of its review, the IMM made a number of recommendations for Market Rule changes and identified areas for additional analysis in 2019. These recommendations will be discussed in more detail at the Participants Committee June 25 Summer Meeting (Agenda Item #14).

- **ISO-NE 2018 FERC Form 714 (not docketed)**

On May 31, 2019, and as revised June 3, ISO-NE submitted its Annual Electric Balancing Authority Area and Planning Area Report for calendar year 2018. 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 2019 Membership Filing (ER19-2021)**

On May 31, NEPOOL requested that the FERC accept (i) the June 1, 2019 memberships of Brookfield Renewable Trading and Marketing LP [Related Person to the Brookfield Companies (Supplier Sector)]; Community Eco Power, LLC (AR Sector, RG Sub-Sector, Large RG Group Seat); DWW Solar II, LLC [Related Person to Deepwater Wind Block Island and Fusion Solar Center, LLC (AR Sector, RG Sub-Sector, Large RG Group Seat)]; and NS Power Energy Marketing, Inc. [Related Person to the Emera Companies (Transmission Sector)]; (ii) the May 1, 2019 termination of the Participant status of Supplier Sector members Mint Energy, LLC; Power Bidding Strategies, LLC; and Utility Expense Reduction LLC; and (iii) the name change of Bridgeport Fuel Cell, LLC (f/k/a Dominion Bridgeport Fuel Cell). Comments on the June Membership filing were due on or before June 21; none were filed. This matter is pending before the FERC.

- **Michael Kuser Membership Filing (ER19-1737)**

On June 18, the FERC accepted the Governance Only End User membership of Michael Kuser (also an *RTO Insider* reporter), effective May 1, 2019.[88] Unless the June 18 order is challenged, this proceeding will be concluded.

- **May 2019 Membership Filing (ER19-1720)**

Also on June 18, the FERC accepted (i) the May 1, 2019 memberships of AES Distributed Energy, Inc. (AR Sector, Renewable Generation Sub-Sector) and Precept Power LLC (Supplier Sector); (ii) the April 1, 2019 termination of the Participant status of Tomorrow Energy Corp.; and (iii) the name changes of Central Rivers Power NH, LLC (f/k/a HSE Hydro NH AC, LLC) and NGV US Transmission Inc. (f/k/a GridAmerica Holdings Inc.).[89] Unless this June 18 order is challenged, this proceeding will be concluded.

- **Involuntary Termination: Lotus Danbury LMS100 One, LLC (ER19-1550)**

On June 3, the FERC accepted the involuntary termination of the NEPOOL membership and Market Participant status of Lotus Danbury LMS100 One, LLC (Provisional Member).[90] As previously reported, NEPOOL and ISO-NE jointly requested the involuntary termination of Lotus Danbury LMS100 One on the basis of on-going

[88] *New England Power Pool Participants Comm.*, Docket No. ER19-1737 (June 18, 2019) (unpublished letter order).

[89] *New England Power Pool Participants Comm.*, Docket No. ER19-1720 (June 18, 2019) (unpublished letter order).

[90] *New England Power Pool Participants Comm. and ISO New England Inc.*, Docket No. ER19-1550 (June 3, 2019) (unpublished letter order).

Payment and Financial Assurance Defaults. The involuntary termination was accepted effective as of June 10, 2019. Unless the June 3 order is challenged, this proceeding will be concluded.

- **Suspension Notices (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 Participants were suspended from the New England Markets on the date indicated (at 8:30 a.m.) due to a Payment Default:

Date of Suspension/ FERC Notice	*Participant Name*	*Date Reinstated*
June 4/6	Stored Solar J&WE, LLC	--
May 9/13	Great American Power	--

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-003-8 (RD19-5)**

On May 21, 2019, NERC filed for approval a revised Reliability Standard CIP-003-8 (Cyber Security – Security Management Controls) to mitigate the risk of malicious code that could result from third-party transient electronic devices for low impact BES Cyber Systems. NERC requested that the CIP-003 changes become effective on the first day of the first calendar quarter that is on the later of: (1) January 1, 2020; or (2) the first day of the first calendar quarter that is six calendar months after the effective date of the FERC's order approving the CIP-003-8 changes, pursuant to the Implementation Plan included with the changes. Comments on the CIP-003-8 changes or due on or before June 12; none were filed. The CIP-0038 changes are pending before the FERC.

- **Revised Reliability Standard: CIP-008-6 (RD19-3)**

On June 20, 2019, the FERC approved a revised Reliability Standard CIP-008-6 (Cyber Security – Incident Reporting and Response Planning) that requires reporting of Cyber Security Incidents that compromise, or attempt to compromise, a Responsible Entity's Electronic Security Perimeter ("ESP") or associated Electronic Access Control or Monitoring Systems ("EACMS") to the Electricity Information Sharing and Analysis Center ("E-ISAC") and the Department of Homeland Security Industrial Control Systems Cyber Emergency Response Team ("ICS-CERT").[91] In addition, the approved require specific information in Cyber Security Incident reports and include deadlines for submitting the reports as directed by the FERC. CIP-008-6 will become effective January 1, 2021.

- **Revised Reliability Standards: FAC-008-4; INT-006-5; INT-009-3; PRC-004-6; Retirement of 10 Standards (Standards Efficiency Review II) (RM19-17)**

On June 7, 2019, in connection with the first phase of work under NERC's Standards Efficiency Review,[92] NERC filed for approval (i) the retirement of individual requirements (not needed for reliability) in the following four Reliability Standards:

[91] *N. Am. Elec. Rel. Corp.*, 167 FERC ¶ 61,230 (June 20, 2019).

[92] The Standards Efficiency Review initiative, which began in 2017, 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.

- FAC-008-4 (Facility Ratings);
- INT-006-5 (Evaluation of Interchange Transactions);
- INT-009-3 (Implementation of Interchange); and
- PRC-004-6 (Protection System Misoperation Identification and Correction).

and (ii) the retirement, in their entirety, of the following 10 Reliability Standards:

- 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-001-1a (Available Transmission System Capability);
- MOD-004-1 (Capacity Benefit Margin);
- MOD-008-1 (Transmission Readability Margin Calculation Methodology);
- MOD-020-0 (Providing Interruptible Demands and Direct Control Load Management Data to System Operators and Reliability Coordinators);
- MOD-028-2 (Area Interchange Methodology);
- MOD-029-2a (Rated System Path Methodology); and
- MOD-030-3 (Flowgate Methodology).

As of the date of this Report, the FERC has not noticed a proposed rulemaking proceeding or otherwise invited public comment.

- **Revised Reliability Standards: IRO-002-7; TOP-001-5; VAR-001-6 (Standards Efficiency Review I) (RM19-16)**

Also on June 7, 2019, and in connection with the first phase of work under NERC's Standards Efficiency Review,[93] NERC filed for approval (i) the retirement of individual requirements (not needed for reliability) in the following three Reliability Standards:

- IRO-002-7 (Reliability Coordination – Monitoring and Analysis);
- TOP-001-5 (Transmission Operations); and
- VAR-001-6 (Voltage and Reactive Control).

As of the date of this Report, the FERC has not noticed a proposed rulemaking proceeding or otherwise invited public comment.

- **NOPR - Revised Reliability Standard: TPL-001-5 (RM19-10)**

On June 20, 2019, the FERC issued a NOPR proposing to approve a revised Reliability Standard -- TPL-001-5 (Transmission System Planning Performance Requirements), and associated implementation plan, VRFs and VSLs (together, the "TPL-001 Changes").[94] As previously reported, NERC stated that the TPL-001 Changes improve upon the currently effective standard by enhancing Requirements for the study of Protection System single points of failure. Additionally, the TLP-001 Changes address two FERC directives from *Order 786*: (1) the TPL-001 Changes provide for a more complete consideration of factors for selecting which known outages will be included in Near-Term Transmission Planning Horizon studies, addressing the FERC's concern that the exclusion of known outages of less than six months in TPL-001-4 could result in outages of significant facilities not being studied; and (2) the TPL-001 Changes modify Requirements for Stability analysis to require an entity to assess the impact of the possible unavailability of long lead time equipment, consistent with the entity's spare equipment strategy. In

[93] The Standards Efficiency Review initiative, which began in 2017, 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.

[94] *Transmission Planning Rel. Standard TPL-001-5*, 167 FERC ¶ 61,249 (June 20, 2019) ("*TPL-001-5 NOPR*").

addition, the FERC proposes in the *TPL-001-5 NOPR* to direct NERC to modify the Reliability Standards to require corrective action plans for protection system single points of failure in combination with a three-phase fault if planning studies indicate potential cascading. Comments on the *TPL-001-5 NOPR* are due [60 days after the NOPR's publication in the *Federal Register*].[95]

- **NOPR - New Reliability Standard: CIP-012-1 (RM18-20)**

On April 18, 2019, the FERC issued a NOPR proposing to approve a new Reliability Standard -- CIP-012-1 (Cyber Security – Communications between Control Centers), and associated Glossary definitions, implementation plan, VRFs and VSLs (together, the "Control Center Cyber Security Communication Changes").[96] The *CIP-012-1 NOPR* also proposes to direct NERC develop certain modifications to CIP-012-1 to require protections regarding the availability of communication links and data communicated between bulk electric system control centers and, further, to clarify the types of data that must be protected. When it filed CIP-012-1, NERC stated that the changes modify the Critical Infrastructure Protection ("CIP") Reliability Standards to require Responsible Entities to implement controls to protect communication links and sensitive Bulk Electric System ("BES") data communicated between BES Control Centers. CIP-012-1 requires Responsible Entities to develop a plan to mitigate the risks posed by unauthorized modification (integrity) and unauthorized disclosure (confidentiality) of Real-time Assessment and Real-time monitoring data. The plan must include the following three components: (1) identification of security protection used to meet the security objective; (2) identification of where the Responsible Entity applied the security protection; and (3) identification of the responsibilities of each Responsible Entity for applying the security protection. Comments on the *CIP-012-1 NOPR* are due on or before June 24, 2019.[97] Thus far, two sets of comments from individuals have been received.

- **Report of Comparisons of Budgeted to Actual Costs for 2018 for NERC and the Regional Entities (RR19-6)**

On May 30, 2019, NERC filed comparisons of actual to budgeted costs for 2018 for NERC and the eight Regional Entities operating in 2018, including NPCC. The Report includes comparisons of actual funding received and costs incurred, with explanations of significant actual cost-to-budget variances, audited financial statements, and tables showing metrics concerning NERC and Regional Entity administrative costs in their 2018 budgets and actual results. Comments on this filing were due on or before June 20, 2019; none were filed. This matter is pending before the FERC.

XI. Misc. - of Regional Interest

- **203 Application: Footprint, Hartree Partners / Brookfield (EC19-104)**

On June 19, 2019, Hartree Partners, Griffith Energy, Cogen Technologies Linden Venture, East Coast Power Linden Holding, Footprint Power Salem Harbor Development ("Footprint") (together, the "Seller Public Utilities"), and Brookfield Asset Management Inc. ("Brookfield") requested authorization for a transaction following which Hartree, Footprint and Brookfield will become Related Persons. The transaction contemplates Brookfield's acquisition of an approximate 62% interest in Oaktree Capital Group, LLC ("Oaktree"), the owner in turn of indirect, upstream interests of greater than 10% in the Seller Public Utilities. Comments on this application are due on or before July 10.

- **203 Application: Empire Generating Co, LLC (EC19-99)**

On June 4, 2019, as amended on June 17,[98] Empire Generating Co, LLC ("Empire") requested authorization for the disposition of its FERC-jurisdictional facilities by way of a bankruptcy-related upstream change in control.

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[95] The *TPL-001-5 NOPR has not yet been* published in the Fed. Reg.

[96] *Critical Infrastructure Protection Rel. Standard CIP-012-1 – Cyber Security – Communications between Control Centers*, 167 FERC ¶ 61,055 (Apr. 18, 2019) ("*CIP-012-1 NOPR*").

[97] The *CIP-012-1 NOPR* was published in the Fed. Reg. on Apr. 18, 2019 (Vol. 84, No. 79) pp. 17,105-17,112.

[98] The June 17 amendment reflected additional owners and affiliates (creditors) associated with the Transaction.

Subject to all required authorizations, including the FERC authorization requested in this proceeding, 100% of the ownership interests in Empire's indirect upstream owner, Empire Gen Holdings, LLC, will be transferred to Empire Acquisition, LLC, which in turn will be owned by certain secured creditors[99] of Empire's current owner, TTK Power, LLC. Comments on the Empire application are due on or before June 25; comments on its amendments, July 8.

Deficiency Letter. In addition, on June 21, the FERC issued a deficiency letter asking that Empire provide the workpapers used to calculate the total post-transaction generation capacity and a Horizontal Competitive Analysis Screen. Empire's responses are due on or before August 5, 2019. Empire's responses will constitute an amendment to its filing, will be publicly noticed for an additional comment period, and will re-set the date by which the FERC must statutorily take action on this filing.

- **203 Application: Kendall Green Energy (EC19-86)**

On May 6, 2019, Kendall Green requested authorization for transaction in which Veolia Energy North America Holdings, Inc. ("Veolia") will become the sole owner of Kendall Green through the acquisition of ISQ Thermal Kendall's remaining 49% share. Comments on the application were due on or before May 28; none were filed. This matter is pending before the FERC.

- **203 Application: Convergent Energy and Power / ECP (EC19-85)**

On June 20, 2019, the FERC authorized a transaction pursuant to which ECP ControlCo, LLC ("ECP") will indirectly acquire 100% of the equity interests in Convergent Energy and Power LP ("Convergent").[100] Upon consummation of the transaction, Convergent will become a Related Person to the Calpine companies. Pursuant to the June 20 order, notice must be filed within 10 days of consummation of the transaction. That notice has not yet been filed.

- **203 Application: Emera Maine/ENMAX (EC19-80)**

On April 24, 2019, Emera Maine requested FERC authorization for a transaction pursuant to which Emera Maine (though not the Emera Energy Service Companies) will become a wholly-owned, indirect subsidiary of ENMAX Corporation, an Alberta corporation wholly-owned by the City of Calgary, Alberta, Canada ("ENMAX"), rather than Emera Inc. Comments on the application were due on or before May 15; none were filed. Eastern Maine Electric Cooperative, MPUC and the Northern Maine Independent System Administrator, Inc. ("NMISA") filed doc-less motions to intervene. This matter is pending before the FERC.

- **203 Application: FirstLight Restructuring (EC19-44)**

On March 12, 2019, the FERC authorized the disposition of jurisdictional facilities that will result from a proposed corporate restructuring involving the transfer of 100% of the electric generating facilities and related assets ("Facilities") of FirstLight Hydro Generating Company ("FirstLight Hydro") to the FirstLight Project Companies[101] ("FirstLight Restructuring"), who will then directly own the Facilities.[102] Among other conditions, the March 12 order required notice within 10 days, which has not yet been filed, of the consummation of the FirstLight Restructuring.

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[99] Various investment funds and entities managed or controlled by Black Diamond Capital Holdings, L.L.C. (93.0%); Various investment funds and entities under management of MJX Asset Management LLC (6.3%); and HSBC Bank plc (0.7%).

[100] *Convergent Energy and Power LP*, 167 FERC ¶ 62,189 (June 20, 2019).

[101] The "FirstLight Project Companies" are FirstLight CT Housatonic, FirstLight CT Hydro, FirstLight MA Hydro, and Northfield Mountain.

[102] *FirstLight Hydro Generating Co. et al.*, 166 FERC ¶ 62,112 (Mar. 12, 2019).

- **203 Application: Dominion Bridgeport Fuel Cell, LLC (EC19-22)**

On May 17, 2019, Dominion Bridgeport Fuel Cell, LLC notified the FERC that its acquisition by FuelCell Energy Finance, a Related Person of AR Sector member DFC ERG CT, which was authorized late last year,[103] was consummated on May 9, 2019. Reporting on this proceeding is now concluded.

- **New England Ratepayers Association Complaint (EL19-10)**

As previously reported, the New England Ratepayers Association ("NERA") filed a complaint on November 2, 2018 seeking declaratory order finding that (i) New Hampshire Senate Bill 365 ("SB 365"),[104] which mandates a purchase price for wholesale sales by seven generators operating in NH, (i) is preempted by the Federal Power Act; (ii) SB 365 violates Section 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA") (because SB 365 does not satisfy the requirement under PURPA and the FERC's implementing regulations[105] that rates set by the states for wholesale sales by QFs may not exceed the purchasing utilities' avoided costs; and (iii) NH is pre-empted from ordering purchases that are contrary to the FERC's order terminating PSNH's mandatory purchase obligation on a service territory-wide basis for QFs with a net capacity in excess of 20 MW. NERA asked the FERC to issue a ruling by February 1, 2019 (the date NH customers may first bear the costs of SB 365). Doc-less interventions were filed by Calpine, Eversource, National Grid, NRG, and the DC Office of People's Counsel. Comments supporting the Petition were filed by: NH OCA, the NH Generator Group,[106] EPSA, and a group of NH customers; a Protest was filed by the State of New Hampshire.[107] The New England Small Hydro Coalition filed comments that, while not taking a position on NERA's preemption argument, disagreed with the premise that underlies NERA's argument as to what constitutes an avoided cost rate in New Hampshire. NH OCA and the NH Generator Group amended/supplemented their December 3 comments. A group of NH Legislators that supported SB 365 filed comments on December 17 urging the FERC to deny the Petition. On December 20, NERA answered the protests and comments.

On January 4, 2019, the NH AG answered NERA's December 20 answer, asserting that NERA's Petition is premature, the evidentiary record before the FERC is inadequate to support the declaratory order sought, and the FERC should dismiss the Petition to allow time for the NHPUC to rule on pending issues before the NHPUC related to the implementation of SB 365. The New Hampshire Generator Group similarly answered NERA's December 20 answer, also asserting that the NERA motion misstated the relevant facts and law. On January 7, PSNH moved to lodge its December 27, 2018 pleading in NHPUC Docket No. DE 18-002 (which objected to the request that the NHPUC determine certain IPP PPAs conform with SB 365/RSA Chap 362-H and noted uncertainties to be resolved in connection with any purchases). On January 22, 2019, the NH Generator Group answered the motion to lodge, providing additional material and context. The FERC has yet to act on this matter. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **PJM MOPR-Related Proceedings (EL18-178; ER18-1314; EL16-49)**

On June 29, 2018, the FERC issued an order ("*PJM Order*")[108] regarding out-of-market support affecting the PJM capacity market.[109] Opening with the statement that "the integrity and effectiveness of the

[103] *Dominion Bridgeport Fuel Cell, LLC*, Docket No. EC19-22 (Dec. 20, 2018).

[104] SB 365, 2018 N.H. Laws Ch. 379, An Act relative to the use of renewable generation to provide fuel diversity, codified at N.H. Rev. Stat. Chapter 362-H.

[105] 18 C.F.R. §§ 292.304(a); 292.101(b)(6) (2018).

[106] The NH Generator Group is comprised of the following entities: Bridgewater Power Company, L.P., DG Whitefield LLC, Pinetree Power – Tamworth LLC, Pinetree Power, Inc., Springfield Power, LLC, and Wheelabrator Concord Company, L.P.

[107] Although the State of New Hampshire requested and was eventually granted a two-week extension of time to file its comments, that extension was noticed on December 4, 2018, after the initial comment date and the submission of NH's comments.

[108] *Calpine Corp. et al.*, 163 FERC ¶ 61,236 (June 29, 2018) ("*June 29, 2018 Order*"), *clarif. and/or reh'g requested*.

capacity market administered by [PJM] have become untenably threatened by out-of-market payments provided or required by certain states for the purpose of supporting the entry or continued operation of preferred generation resources," the *PJM Order* determined that the PJM Tariff is currently unjust and unreasonable, rejected PJM's Section 205 Filing, granted in part Calpine's Complaint, and established a paper hearing to resolve the "price-suppressive" effects of out-of-market support for certain resources. Commissioners LaFleur and Glick both dissented, and Commissioner Powelson wrote a separate concurrence.

In the *PJM Order*, the FERC found "that it has become necessary to address the price suppressive impact of resources receiving out-of-market support." The FERC agreed with Calpine and PJM that changes to the PJM Tariff were required, but did not accept the changes proposed in the Calpine Complaint or the PJM Filing, finding that neither had been shown to be just and reasonable, and not unduly discriminatory or preferential. The majority stated that it was unable to determine, based on the record of either proceeding, the just and reasonable rate to replace the rate in PJM's Tariff. The *PJM Order* therefore found the PJM Tariff unjust and unreasonable, granted the Calpine Complaint, in part, and *sua sponte* initiated a new FPA section 206 proceeding (EL18-178), consolidating the record of the two earlier proceedings, and setting for paper hearing the issue of how to address a proposed alternative put forth in the *PJM Order,*[110] which would modify two existing aspects of the PJM Tariff, "or any other proposal that may be presented."

16 requests for clarification and/or rehearing of the *PJM Order* were filed on July 30, 2018. On August 29, 2018, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending.

Paper Hearing; Additional Briefing; PJM's Extended RCO Proposal. Following an August 22 notice of extension of time, interested parties were invited to submit their initial round of testimony, evidence, and/or argument by October 2, 2018. Initial briefs, comments and submissions were filed by over 50 parties. In its October 2 submission, PJM submitted a revised proposal, which includes an expanded MOPR coupled with a "Extended Resource Carve-Out" proposal ("Extended RCO"). The proposed MOPR would apply to all fuel and technology types and to both existing and new resources (a change from the original MOPR, which only applied to new gas-fired units). The Extended RCO would provide a means for states to support particular subsidized generation assets by removing them from certain aspects of the PJM capacity market and not subjecting them to MOPR in PJM's capacity market.

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[109] The *PJM Order* addressed two separate, but related proceedings. The first, EL16-49, was initiated by a complaint originally filed by Calpine, joined by additional generation entities ("Calpine Complaint") on March 21, 2016, and later amended on January 9, 2017. The Calpine Complaint argued that PJM's MOPR was unjust and unreasonable because it did not address the impact of existing resources receiving out-of-market payments on the capacity market, and proposed interim tariff revisions that would extend the MOPR to a limited set of existing resources. The Calpine Complaint also requested the FERC to direct PJM to conduct a stakeholder process to develop and submit a long-term solution. The second proceeding was PJM's filing of its proposed revisions to its Tariff, pursuant to section 205 of the FPA in ER18-1314 ("PJM Filing"). The PJM Filing consisted of two alternate proposals designed to address the price impacts of state out-of-market support for certain resources. The first approach, preferred by PJM but not supported by its stakeholders, consisted of a two-stage annual auction, with capacity commitments first determined in stage one of the auction and the clearing price set separately in stage two ("Capacity Repricing"). The second alternative approach, proposed in the event that the FERC determined that Capacity Repricing was unjust and unreasonable, would have revised PJM's MOPR to mitigate capacity offers from both new and existing resources, subject to certain proposed exemptions ("MOPR-Ex").

[110] The proposed alternative approach would (i) modify PJM's MOPR such that it would apply to new and existing resources that receive out-of-market payments, regardless of resource type, but would include few to no exemptions; and (ii) in order to accommodate state policy decisions and allow resources that receive out-of-market support to remain online, establish an option in PJM's Tariff that would allow, on a resource-specific basis, resources receiving out-of-market support to choose to be removed from the PJM capacity market, along with a commensurate amount of load, for some period of time. That option, which is similar in concept to the Fixed Resource Requirement ("FRR") that currently exists in PJM's Tariff, is referred to as the "FRR Alternative." Unlike the existing FRR construct, the FRR Alternative would apply only to resources receiving out-of-market support. Both aspects of the proposed replacement rate, along with a series of questions that need to be addressed, are more fully explained and raised in the *PJM Order*.

Reply testimony, evidence, and/or argument was due on or before November 6, 2018. Over 60 sets of reply briefs, evidence, etc. were filed. Since that time, a few parties submitted answers and additional comments. On December 6, PJM and Direct Energy/NextEra filed limited answers to reply briefs. In addition, a letter from a group of companies representing competitive new generation built in the PJM region since 2010 ("Generator Letter") urged the FERC to "to consider the broadest ramification of a fundamental change in the regulatory compact and the impact it would have on consumers, investors and even the fundamental American belief that markets drive better outcomes than government."[111] Answers to and comments on PJM's answer were filed by "Clean Energy Entities"[112] and UCS. Responses to the December 6 Generators Letter were filed by APPA, ELCON, LPPC, NRECA, and NRDC. On December 28, PSEG submitted supplemental comments. On January 15, PSEG answered PSEG's supplemental comments. These materials, together with all of the initial briefs and reply briefs, are still pending before the FERC.

The FERC committed in the *PJM Order* to make every effort to issue an order establishing the just and reasonable replacement rate no later than January 4, 2019 (a date which has long since passed). The FERC also established a refund effective date of March 21, 2016, the date of the original Calpine Complaint in EL16-49.

On March 11, 2019, PJM submitted an informational filing notifying the FERC that, given the lack of a final FERC order in this proceeding, it instructed Capacity Market Sellers to follow all relevant pre-auction deadlines under ***both*** the existing capacity market rules as well as PJM's proposed Capacity Reform rules (with revised MOPR rules and the Extended RCO alternative), in connection with the upcoming 2022/2023 Delivery Year Base Residual Auction ("BRA") scheduled to begin on August 14, 2019. PJM urged the FERC to issue an order expeditiously. On April 3, 2019, Joint Consumer Advocates[113] also urged the FERC rule in this matter.

PJM Motion for Supplemental Clarification. On April 10, PJM submitted a Motion for Supplemental Clarification of the *June 29, 2018 Order* setting forth its intention to run the August 2019 BRA under its existing capacity market rules and seeking confirmation that, to the extent the FERC has not established a replacement rate prior to the August 2019 BRA, any replacement rate later established by the FERC would be applied prospectively and would not require PJM to re-run the August 2019 BRA. Answers to the Motion were filed by PJM Entities[114] (requesting the FERC establish a revised commencement date and schedule) and the IL AG (requesting that the FERC require PJM to replace the clearing price setting algorithm ahead of running the BRA and to release generator bidding data 30 days after the BRA). EPSA, Clean Energy Entities and Direct Energy each filed comments supporting the PJM Motion. EPSA protested the PJM Entities' April 25 answer (because it is procedurally defective and would only serve to inject further uncertainty into the market).

For further information on this proceeding, please contact Jamie Blackburn (202-218-3905; jblackburn@daypitney.com).

- **PJM Clean MOPR Complaint (EL18-169)**

This proceeding, which could impact potentially impact New England's markets, remains pending. As previously reported, CPV Power Holdings, L.P. ("CPV"), Calpine Corporation ("Calpine"), and Eastern Generation, LLC ("Eastern Generation") (collectively, "PJM MOPR Complainants") filed a complaint on May 31, 2018 requesting that the FERC protect PJM's Reliability Pricing Model ("RPM") market from below-cost offers

[111] Those companies included: Ares Power and Infrastructure Group, Caithness, Calpine, Carroll County and South Field Energy, CPV, J-POWER USA Development Co., Panda Power Funds, and Tenaska Energy.

[112] "Clean Energy Entities" are AWEA, the Solar RTO Coalition, Solar Energy Industries Assoc., Advanced Energy Economy ("AEE"), the American Council on Renewable Energy ("ACORE"), and the Mid-Atlantic Renewable Energy Coalition ("MAREC").

[113] "Joint Consumer Advocates" were the NJ Division of Rate Counsel, DE Division of the Public Advocate, the DC Office of the People's Counsel, the PA Office of Consumer Advocate, MD Office of People's Counsel and the IL Citizens Utility Board.

[114] "PJM Entities are AMP, Dominion, Exelon, EDP Renewables, FirstEnergy and the Talen PJM Companies.

for resources receiving out-of-market subsidies by requiring PJM to adopt a "Clean MOPR" (i.e. a MOPR applicable to all subsidized resources and without categorical exemptions like those in PJM's MOPR-Ex proposal). PJM MOPR Complainants state that the Complaint offers the FERC a procedural vehicle to require adoption of the "Clean MOPR" that Complainants opine is not otherwise available in pending FERC proceedings (EL16-49 (PJM MOPR Complaint)[115] and ER18-1314 (PJM's pending MOPR changes)). They assert that the "Clean MOPR" is required to effectively address the impacts of state subsidy programs, and is consistent with the FERC's MOPR principles identified in the *CASPR Order*. Comments on the PJM Clean MOPR Complaint were due on or before June 20. PJM's answer, as well as comments and protests from over 25 parties were filed. Given its potential to impact New England, NEPOOL filed a doc-less motion to intervene. More than 30 other parties also intervened. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- ***NYISO MOPR Proceeding (EL13-62)***

As in the PJM MOPR Proceeding, NEPOOL filed limited comments requesting that any FERC action or decision be limited narrowly to the facts and circumstances as presented, and that any changes ordered by the FERC not circumscribe the results of NEPOOL's stakeholder process or predetermine the outcome of that process through dicta or a ruling. The NYISO MOPR Proceeding remains pending before the FERC. If you have any questions concerning this proceeding, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **PJM Retroactive Surcharges (EL08-14)**

In a decision which could impact the resolution of future cases in New England, the FERC reversed its prior position on the issue of ordering refunds in cost allocation and rate design cases, and found that it does in fact have authority under the FPA to order refunds to fix an error, even if refunds will require surcharges on other parties.[116] Although the FERC acknowledged that it had "in the past has referenced a general policy of not ordering refunds in cost allocation and rate design cases", it found that it "has greater discretion with respect to this refund-related issue under sections 309 and 206(b) of the FPA than was indicated by those statements."[117] Summarizing recent court precedent, the FERC concluded that retroactive surcharges were not prohibited in all circumstances, and refunds and surcharges are allowable in situations in which surcharges are necessary if the statutory refund provision of Section 206 of the FPA is to be honored.[118] Going forward, the FERC stated that it will consider whether to require refunds in cost allocation and rate design cases based on the specific facts and equities of each case, even where such refunds must be funded through surcharges on certain parties, to meet its obligation under section 206(b) of the FPA to restore the just and reasonable rate.[119]

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[115] The "PJM MOPR Complaint" seeks a FERC order expanding the PJM MOPR in the Base Residual Auction for the 2019/2020 Delivery Year to prevent the artificial suppression of prices in the Reliability Pricing Model ("RPM") market by below-cost offers for existing resources whose continued operation is being subsidized by State-approved out-of-market payments. Complainants in the MOPR Complaint are Calpine, Dynegy, Eastern Generation, Homer City Generation, the NRG Companies, Carroll County Energy, C.P. Crane , the Essential Power PJM Companies, GDF SUEZ Energy Marketing NA, Oregon Clean Energy, and Panda Power Generation Infrastructure Fund.

[116] *Black Oak Energy, EPIC Merchant Energy, and SESCO Enterprises v. PJM Interconnection*, 167 FERC ¶ 61,250 (June 20, 2019).

[117] *Id.* at P 15. FPA section 206(a) authorizes the FERC to fix rates prospectively, after it concludes that a rate is inappropriate, and to order refunds where the previous rate was unfairly high. With respect to the retroactive correction of rates that were too low, FPA section 309 gives the FERC expansive remedial authority to advance remedies not expressly provided by the FPA, as long as they are consistent with the FPA. Reallocation of costs, including through surcharges, has been found to be within the FERC's remedial authority under section 309, read in harmony with section 206 (the cost increase to a subgroup of ratepayers not being a retroactive rate increase because the aggregate rate remains the same, albeit divided differently among the constituent payers).

[118] *Id.* at P 26.

[119] *Id.* at P 27.

- **D&E Agreement: NSTAR/Vineyard Wind (ER19-2171)**

On June 17, NSTAR filed an Agreement for Design, Engineering and Construction services ("D&E Agreement") between itself and Vineyard Wind, LLC ("Vineyard Wind"). The purpose of the D&E Agreement is to set forth the terms and conditions under which NSTAR will undertake and be reimbursed for certain preliminary design and engineering activities in connection with the interconnection of Vineyard Wind's 832 MW wind farm off the shores of Massachusetts. NSTAR requested that the D&E Agreement become effective as of the date of filing. The D&E Agreement will expire no later than the effective date of the LGIA that will be entered into among NSTAR, Vineyard Wind and ISO-NE, unless earlier terminated by the parties. Comments on this filing are due on or before July 8. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **RFA Termination: NSTAR/Pilgrim (ER19-2108)**

On June 11, NSTAR filed a notice of termination of the Related Facilities Agreement between NSTAR, f/k/a Boston Edison Company, and Entergy Nuclear Generation Company ("Entergy") (the "RFA"). The RFA terminated June 1, 2019 as a result of the May 31, 2019 11:59 p.m. retirement of the Pilgrim facility from the New England Markets, which terminated Pilgrim's interconnection rights, and the transfer of the ownership of Pilgrim's 345 kV transmission switchyard from Entergy to NSTAR. NSTAR requested a June 1, 2019 effective date for the RFA termination notice. Comments on this filing are due on or before July 2. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **IA Termination: Pilgrim (ER19-2046)**

On June 4, NSTAR filed a notice of termination of the Interconnection and Operation Agreement between NSTAR, f/k/a Boston Edison Company, and Entergy Nuclear Generation Company ("Entergy") (the "IA"). The IA terminated June 1, 2019 as a result of the May 31, 2019 11:59 p.m. retirement of the Pilgrim facility from the New England Markets, which terminated Pilgrim's interconnection rights, and the transfer of the ownership of Pilgrim's 345 kV transmission switchyard from Entergy to NSTAR. NSTAR requested a June 1, 2019 effective date for the termination notice. Comments on this filing are due on or before June 25. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Emera Maine/Houlton Water Company NITSA (ER19-2036)**

On June 3, Emera Maine filed a non-conforming Network Integration Transmission Service Agreement ("NITSA") with Houlton Water Company. The NITSA provides for continued provision of network integration transmission service by Emera Maine to Houlton until Houlton's electric system is successfully interconnected with New Brunswick Power, which is expected to happen sometime in late 2019. A June 1, 2019 effective date was requested. Comments on this filing are due on or before June 24. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement: CL&P/NTE CT (ER19-1994)**

On May 28, CL&P filed an Agreement for Design, Engineering and Construction services ("D&E Agreement") between itself and NTE Connecticut, LLC ("NTE CT"). The purpose of the D&E Agreement is to set forth the terms and conditions under which CL&P will undertake and be reimbursed for certain preliminary design and engineering activities in connection with the interconnection of NTE CT's 692 MW generation facility to CL&P's system in Killingly, CT. The parties requested that the D&E Agreement become effective as of the date of filing. The D&E Agreement will expire no later than the effective date of the LGIA among CL&P, NTE CT and ISO-NE, currently being finalized (as long as that date occurs by May 28, 2020). Comments on this filing were due on or before June 18; 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).

- ***Emera Maine* Order 845 Compliance Filing (ER19-1887)**

On May 17, 2019, in response to the requirements of *Order 845*, Emera Maine submitted changes to the LGIP and LGIA in its Open Access Transmission Tariff for the Maine Public District (the "MPD OATT"). Emera Maine request a May 20, 2019 effective for the changes. Though no comments were filed, the FERC issued a letter in a number of utility filing proceedings, including this one, requesting additional information related to the provisions for surplus interconnection service be filed within 30 days (or July 15). The response to the FERC's letter will constitute an amendment to the filing and will be noticed for comment. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement Cancellation: NSTAR/National Grid (Wynn Casino) (ER19-1395)**

On May 7, the FERC accepted a notice of cancellation filed by NSTAR of the Design and Engineering Agreement ("D&E Agreement") between NSTAR and National Grid (designated as service agreement IA-NSTAR-36).[120] As previously reported, the D&E Agreement set forth the terms and conditions under which National Grid would reimburse NSTAR undertook for costs associated with the interconnection of Wynn Casino. With the completion of NSTAR's services, the D&E Agreement terminated by its own terms. The notice of cancellation was accepted March 21, 2019, as requested. The May 7 order was not challenged and is final and unappealable. This proceeding is concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Mystic COS Agreement Amendment No. 1 (ER19-1164)**

On March 1, 2019, Constellation Mystic Power, LLC ("Mystic") filed (separately from its contemporaneously-submitted compliance filing) and amendment to its COS Agreement to provide "reciprocal early termination rights for ISO-NE and Mystic based on the results of ISO-NE's updated fuel security analysis, to be completed in September of 2019". Comments on this filing were due on or before March 22, 2019. Protests were filed by CT Parties, ENECOS, MMWEC/NHEC, and Verso. Doc-less interventions were filed by Avangrid, Environmental Defense Fund, Eversource, MA DPU, National Grid, NESCOE, Repsol, and the New England Local Distribution Companies. On April 8, Mystic answered the March 22 protests. 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).

- **CMP & UI/Brookfield Phase I/II HVDC-TF Service Agreements (ER19-1105 et al.)**

On May 2, 2019, the FERC accepted three new Phase I/II HVDC-TF Service Agreements with Brookfield Energy Marketing LP ("Brookfield") filed February 22, 2019 by CMP and UI (which allow the continuation without interruption of service provided pursuant to existing agreements that conform to the pro forma Phase I/II HVDC-TF Service Agreement set forth in Attachment A of Schedule 20A–Common to the ISO-NE OATT).[121] The Service Agreements were separately filed and docketed – "CMP-Brookfield 85 MW" (ER19-1105); "UI-Brookfield 1 MW" (ER19-1106); and "UI-Brookfield 32 MW" (ER19-1107). The Service Agreements allow Brookfield to retain its rollover rights and right of first refusal in a manner that takes into account the fact that the current contractual rights of UI and CMP to capacity over the Phase I/II HVDC-TF under the Support Agreements only extend until October 31, 2020. The Agreements were accepted, as requested, with effective dates of January 1, 2020 for CMP-Brookfield 85 MW and for UI-Brookfield 1 MW and September 1, 2020 for UI-Brookfield 32 MW. The May 2 orders were not challenged and are final and unappealable. These proceedings are now concluded. If you have any questions concerning these matters, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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[120] *NSTAR Elec. Co.*, Docket No. ER19-1395 (May 7, 2019) (unpublished letter order).

[121] *See Central Maine Power Co.*, Docket No ER19-1105 (May 2, 2019) (unpublished letter order) (accepting CMP-Brookfield 85 MW); *The United Illuminating Co.*, Docket No. ER19-1106 (May 2, 2019) (unpublished letter order) (accepting UI-Brookfield 1 MW); *The United Illuminating Co.*, Docket No. ER19-1107 (May 2, 2019) (unpublished letter order) (accepting UI-Brookfield 32 MW).

- **FERC Enforcement Action: Dominion Energy Virginia (IN19-3)**

On May 3, the FERC approved a Stipulation and Consent Agreement with Virginia Electric and Power Company (doing business as Dominion Energy Virginia ("Dominion Energy Virginia" or "DEV")[122] that resolved OE's investigation into whether DEV violated any FERC rules, including the Anti-Manipulation Rule, related to DEV's receipt of lost opportunity cost credits ("LOCCs") in the PJM market. OE determined that from April 1, 2010 to March 31, 2011, DEV engaged in a strategy to target and maximize its receipt of LOCCs by offering its combustion turbine units ("CT units") in the Day-Ahead market (DA) with price-based offers with substantially increased start-up and no-load values than previously used and with discounted incremental energy offers. OE determined that this strategy sought to obtain more DA commitments, by correspondingly lowering the incremental energy offers in the CT units' offers, and at the same time, sought to reduce the chance the units were dispatched by PJM in Real-Time, by increasing the start-up values in the offers. OE further determined that this strategy increased LOCC payouts in certain hours when the CT units had a risk of operating at a loss. OE concluded that DEV's conduct violated the Anti-Manipulation Rule because DEV offered its CT units in a manner that sought to target and maximize LOCCs, rather than making the units available to the market based on supply and demand fundamentals. OE concluded that DEV's conduct was contrary to the purpose of LOCCs and impaired the functioning of the LOCC provisions of the PJM market and PJM's unit commitment process (noting that LOCCs are not intended to be an incentive to generators to design offers that seek to target and maximize LOCCs or discourage PJM's dispatch of units in Real-Time). Under the Settlement, in which DEV neither admits nor denies the alleged violations, DEV must ***disgorge $7 million*** (which includes interest) to PJM, to be allocated by PJM in its discretion for the benefit of PJM customers and upon approval by OE's of PJM's plan for doing so, and ***pay a $7 million civil penalty*** to the United States Treasury. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **FERC Enforcement Action: Order of Non-Public, Formal Investigation (IN15-10)**

MISO Zone 4 Planning Resource Auction Offers. On October 1, 2015, the FERC issued an order authorizing the Office of Enforcement ("OE") to conduct a non-public, formal investigation, with subpoena authority, regarding violations of FERC's regulations, including its prohibition against electric energy market manipulation, that may have occurred in connection with, or related to, MISO's April 2015 Planning Resource Auction for the 2015/16 power year. There has been no public update provided since that order.

XII. Misc. - Administrative & Rulemaking Proceedings

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

On January 8, 2018, the FERC initiated a Grid Resilience in RTO/ISOs proceeding (AD18-7)[123] and terminated the DOE NOPR rulemaking proceeding (RM18-1).[124] In terminating the DOE NOPR proceeding, the FERC concluded that the Proposed Rule and comments received did not support FERC action under Section 206 of the FPA, but did suggest the need for further examination by the FERC and market participants of the risks that the bulk power system faces and possible ways to address those risks in the changing electric markets. On February 7,

[122] *Virginia Elec. and Power Co.*, 167 FERC ¶ 61,103 (May 3, 2019).

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

[124] As previously reported, the FERC opened the DOE NOPR proceeding in response to a September 28, 2017 proposal by Energy Secretary Rick Perry, issued under a rarely-used authority under §403(a) of the Department of Energy ("DOE") Organization Act, that would have required RTO/ISOs to develop and implement market rules for the full recovery of costs and a fair rate of return for "eligible units" that (i) are able to provide essential energy and ancillary reliability services, (ii) have a 90-day fuel supply on site in the event of supply disruptions caused by emergencies, extreme weather, or natural or man-made disasters, (iii) are compliant with all applicable environmental regulations, and (iv) are not subject to cost-of-service rate regulation by any State or local authority. More than 450 comments were submitted in response to the DOE NOPR, raising and discussing an exceptionally broad spectrum of process, legal, and substantive arguments. A summary of those initial comments was circulated under separate cover and can be found with the posted materials for the November 3, 2017 Participants Committee meeting. Reply comments and answers to those comments were filed by over 100 parties.

FRS requested rehearing of the January 8 order terminating the DOE NOPR proceeding. The FERC issued a tolling order on March 8, 2018 affording it additional time to consider the FRS request for rehearing, which remains pending.

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

ISO-NE Response. In its response, ISO-NE identified fuel security[125] as the most significant resilience challenge facing the New England region. ISO-NE reported that it has established a process to discuss market-based solutions to address this risk, and indicated that it believed it will need through the second quarter of 2019 to develop a solution and test its robustness through the stakeholder process. In the meantime, ISO-NE indicated that it would continue to independently assess the level of fuel-security risk to reliable system operation and, if circumstances dictate, would take, with FERC approval when required, actions it determines to be necessary to address near-term reliability risks. ISO-NE's response was broken into three parts: (i) an introduction to fuel-security risk; (ii) background on how ISO-NE's work in transmission planning, markets, and operations support the New England bulk power system's resilience; and (iii) answers to the specific questions posed in the January 8 order.

Industry Comments. Following a 30-day extension issued on March 20, 2018, reply comments were due on or before May 9, 2018. NEPOOL's comments, which were approved at the May 4 meeting, were filed May 7, and were among over 100 sets of initial comments filed. A summary of the comments that seemed most relevant to New England and NEPOOL was circulated to the Participants Committee on May 15 and is posted on the NEPOOL website. On May 23, NEPOOL submitted a limited response to four sets of comments, opposing the suggestions made in those pleadings to the extent that the suggestions would not permit full use of the Participant Processes. Supplemental comments and answers were also filed by FirstEnergy, MISO South Regulators, NEI, and EDF. Exelon and American Petroleum Institute filed reply comments. FirstEnergy included in this proceeding its motion for emergency action also filed in ER18-1509 (ISO-NE Waiver Filing: Mystic 8 & 9), which Eversource answered (in both proceedings). Reply comments were filed by APPA and American Municipal Power ("AMP") and the Nuclear Energy Institute ("NEI") moved to lodge presentations by the National Infrastructure Advisory Council. On December 6, the Harvard Electricity Law Initiative filed a comment suggesting that, as a matter of law, "Commission McNamee cannot be an impartial adjudicator in these proceedings" and "any proceeding about rates for 'fuel-secure' generators" and should recuse himself. Similarly, on December 18, "Clean Energy Advocates"[126] requested Commissioner McNamee recuse himself from these proceedings. These matters remain pending before the FERC.

FirstEnergy DOE Application for Section 202(c) Order. In a related but separate matter, FirstEnergy Solutions ("FirstEnergy") asked the Department of Energy ("DOE") in late March to issue an emergency order to provide cost recovery to coal and nuclear plants in PJM, saying market conditions there are a "threat to energy security and reliability". FirstEnergy made the appeal under Section 202(c) of the FPA, which allows the DOE to issue emergency orders to keep plants operating, but has previously been exercised only in response to natural disasters. Action on that 2018 request is pending.

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

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

- **Increasing Market and Planning Efficiency Through Improved Software (AD10-12)**

The FERC will hold a technical conference addressing increasing Real-Time and Day-Ahead market efficiency through improved software June 25-27, 2019. This is the tenth consecutive year that the FERC has held a summer conference on this topic. FERC Staff will be facilitating a discussion to explore research and operational advances with respect to market modeling that appear to have significant promise for potential efficiency improvements. Initial and final agendas were posted on May 24 and June 20, 2019, respectively. Those planning to attend the conference should register through the FERC's website. The FERC will accept comments following the conference, with a deadline of July 31, 2019.

- **NOPR: Public Util. Trans. ADIT Rate Changes (RM19-5)**

On November 15, 2018, the FERC issued a NOPR ("*ADIT NOPR*") proposing to require 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").[127] Specifically, for transmission formula rates, the FERC is proposing (i) to require that public utilities 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; (ii) to require all public utilities with transmission formula rates to incorporate a new permanent worksheet into their transmission formula rates that will annually track ADIT information; (iii) to require all public utilities with transmission stated rates to determine the amount of excess and deferred income tax caused by the 2017 Tax Law's reduction to the federal corporate income tax rate and return or recover this amount to or from customers. As previously reported, comments on the *ADIT NOPR* were due on or before January 22, 2019. Comments were filed by over 14 parties, including Eversource, EEI, and NRECA. The *ADIT NOPR* is pending before the FERC.

- **NOPR: Refinements to Horizontal Market Power Analysis Requirements (RM19-2)**

On December 20, 2018, the FERC issued a NOPR proposing to relieve market-based rate sellers of the obligation, when seeking to obtain or retain market-based rate authority in any RTO/ISO market with RTO/ISO-administered energy, ancillary services, and capacity markets subject to FERC-approved RTO/ISO monitoring and mitigation, to submit indicative screens ("*Horizontal Market Power Analysis Refinements NOPR*").[128] In RTOs and ISOs that lack an RTO/ISO-administered capacity market, market-based rate sellers would be relieved of the requirement to submit indicative screens if their market-based rate authority is limited to sales of energy and/or ancillary services. The FERC's regulations would continue to require RTO/ISO sellers to submit indicative screens for authorization to make capacity sales in any RTO/ISO markets that lack an RTO/ISO-administered capacity market subject to FERC-approved RTO/ISO monitoring and mitigation. The *NOPR* also proposes to eliminate the rebuttable presumption that FERC-approved RTO/ISO market monitoring and mitigation is sufficient to address any horizontal market power concerns regarding sales of capacity in RTOs/ISOs that do not have an RTO/ISO-administered capacity market. Comments on the *Horizontal Market Power Analysis Refinements NOPR* were due March 18, 2019.[129] Comments were filed by over 20 parties, including Calpine, EDF Renewables, APPA/NRECA/American Antitrust Institute, EEI, ELCON, EPSA, the Organization of PJM States, and the PJM IMM. Reply comments were submitted by PG&E and the CAISO IMM. EEI submitted supplemental comments on April 29, 2019. Since the last Report, PJM answered the PJM IMM's Comments on May 7 and the PJM IMM answered PJM's May 7 comments on May 23. The *Horizontal Market Power Analysis Refinements NOPR* remains pending before the FERC.

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[127] *Public Util. Trans. Rate Changes to Address Accumulated Deferred Income Taxes*, 165 FERC ¶ 61,117 (Nov. 15, 2018).

[128] *Refinements to Horizontal Market Power Analysis for Sellers in Certain Regional Trans. Org. and Indep. Sys. Op. Mkts.*, 165 FERC ¶ 61,091 (Dec. 20, 2018)

[129] The *Horizontal Market Power Analysis Refinements NOPR* was published *Fed. Reg.* on Feb. 1, 2019 (Vol. 84, No. 22) pp. 993-1,106.

- **DER Participation in RTO/ISOs (RM18-9)**

In *Order 841*[130] (*see* RM16-23 below), the FERC initiated a new proceeding in order to continue to explore the proposed distributed energy resource ("DER") aggregation reforms it was considering in the *Storage NOPR*.[131] All comments filed in response to the *Storage NOPR* will be incorporated by reference into Docket No. RM18-9 and further comments regarding the proposed distributed energy resource aggregation reforms, including comments regarding the April 10-11 technical conference in AD18-10,[132] were also to be filed in RM18-9. On June 26, 2018, over 50 parties submitted post-technical conference comments in this proceeding, including comments from ISO-NE, Calpine, Direct, Eversource, Icetec, NRG, Utility Services, EEI, EPRI, EPSA, NARUC, NRECA, and SEI. On February 11, 2019, a group of 18 US Senators submitted a letter urging the FERC to adopt a final rule that enable all DERs the opportunity to participate in the RTO/ISO markets and requesting an update no later than March 1, 2019. Reply comments and answers were submitted by the Arkansas PUC, Advanced Energy Economy, AEMA, and the Missouri PUC. APPA/NRECA submitted supplemental comments. This matter remains pending before the FERC.

- ***Orders 845/845-A*: LGIA/LGIP Reforms (RM17-8)**

Order 845. As previously reported, the FERC issued on April 19, 2018, its final rule,[133] *Order 845*, revising its *pro forma* Large Generator Interconnection Procedures ("LGIP") and *pro forma* LGIA to implement 10 specific reforms designed to improve certainty for interconnection customers,[134] promote more informed interconnection decisions,[135] and enhance the interconnection process.[136] Based on the comments received on its December 15, 2016 NOPR[137] in this proceeding as well as other factors, *Order 845* declined to adopt four proposed reforms related to requiring periodic restudies, self-funding of network upgrades, the posting of congestion and curtailment information, and the modeling of electric storage resources. *Order 845* took no

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[130] *Elec. Storage Participation in Mkts. Operated by Regional Trans. Orgs. and Indep. Sys. Operators*, Order No. 841, 162 FERC ¶ 61,127 (Feb. 15, 2018), reh'g and/or *clarif. requested* ("*Order 841*").

[131] *Elec. Storage Participation in Mkts. Operated by Regional Trans. Orgs. and Indep. Sys. Operators*, 157 FERC ¶ 61,121 (Nov. 17, 2016) ("*Storage NOPR*").

[132] On April 10-11, 2018, the FERC held a technical conference to gather additional information to help the FERC determine what action to take on DER aggregation reforms proposed in the *Storage NOPR* and to explore issues related to the potential effects of DERs on the bulk power system. Technical conference materials are posted on the FERC's eLibrary. Interested persons were invited to file post-technical conference comments on the topics concerning the Commission's DER aggregation proposal discussed during the technical conference, including on follow-up questions from FERC Staff related to the panels. Comments related to DER aggregation were to be filed in RM18-9; comments on the potential effects of DERs on the bulk power system, in AD18-10.

[133] *Reform of Generator Interconnection Procedures and Agreements*, Order No. 845, 163 FERC ¶ 61,043 (Apr. 19, 2018) ("*Order 845*").

[134] To improve certainty for interconnection customers, *Order 845* (1) removes the limitation that interconnection customers may only exercise the option to build a transmission provider's interconnection facilities and stand-alone network upgrades in instances when the transmission provider cannot meet the dates proposed by the interconnection customer; and (2) requires that transmission providers establish interconnection dispute resolution procedures that allow a disputing party to unilaterally seek non-binding dispute resolution.

[135] To promote more informed interconnection decisions, *Order 845* (1) requires transmission providers to outline and make public a method for determining contingent facilities; (2) requires transmission providers to list the specific study processes and assumptions for forming the network models used for interconnection studies; (3) revises the definition of "Generating Facility" to explicitly include electric storage resources; and (4) establishes reporting requirements for aggregate interconnection study performance.

[136] To enhance the interconnection process, *Order 845* (1) allows interconnection customers to request a level of interconnection service that is lower than their generating facility capacity; (2) requires transmission providers to allow for provisional interconnection agreements that provide for limited operation of a generating facility prior to completion of the full interconnection process; (3) requires transmission providers to create a process for interconnection customers to use surplus interconnection service at existing points of interconnection; and (4) requires transmission providers to set forth a procedure to allow transmission providers to assess and, if necessary, study an interconnection customer's technology changes without affecting the interconnection customer's queued position.

[137] *Reform of Generator Interconnection Procedures and Agreements*, 157 FERC ¶ 61,212 (Dec. 15, 2016) ("*LGIP/LGIA Reforms NOPR*"). The *LGIP/LGIA Reforms NOPR* was published in the *Fed. Reg.* on Jan. 13, 2017 (Vol. 82, No. 9) pp. 4,464-4,501.

action on two additional issues raised in the NOPR -- cost caps for network upgrades and affected system coordination (which is being addressed in a separate proceeding). *Order 845* became effective July 23, 2018.

Order 845-A. On February 21, 2019, the FERC issued its order on rehearing and clarification of *Order 845* ("*Order 845-A*").[138] The FERC granted rehearing in full or in part of four requests and clarification with respect to seven requests. The FERC ***granted rehearing*** with regard to (a) the option to build reform (requiring that transmission providers explain why they do not consider a specific network upgrade to be a standalone network upgrade; and allowing transmission providers to recover oversight costs related to the interconnection customer's option to build), (b) surplus interconnection service reform (explaining that RTOs/ISOs will not be limited in their arguments for an independent entity variation from the requirements), and (c) when an interconnection customer can propose control technologies in connection with interconnection service below generating facility capacity (control technologies may be proposed at any time in the interconnection process that it is permitted to request interconnection service below generating facility capacity). The FERC granted clarification with regard to (w) the option to build provisions (finding *Order 845* applies to all public utility transmission providers, including those that reimburse the interconnection customer for network upgrades, and does not apply to stand alone network upgrades on affected systems), (x) study model and assumption transparency (finding that transmission providers may use the FERC's CEII regulations as a model for evaluating entities that request network model information and assumptions and the phrase "current system conditions" does not require transmission providers to maintain network models that reflect current real-time operating conditions of the transmission provider's system), (y) interconnection study deadlines (transmission providers are not required to post 2017 interconnection study metrics) and (z) transmission providers must provide a detailed explanation of its determination to perform additional studies at the full generating facility capacity for an interconnection customer that has requested service below its full generating facility capacity. All other requests for rehearing and clarification were denied. On March 25, AEP requested rehearing of *Order 845-A*. AWEA answered AEP's rehearing request on May 21. On April 23, 2019, the FERC issued a tolling order affording it additional time to consider AEP's request, which remains pending.

Effective Date and Compliance Filing Deadline. *Order 845-A* became effective May 20, 2019.[139] The *Order 845* compliance filing deadline was ***May 22, 2019***. Additionally, for each RTO/ISO, "the effective date of the proposed revisions shall be the date established in the Commission's order accepting that RTO's/ISO's compliance filing, which will be no earlier than the issuance date of such an order." ISO-NE's *Order 845* compliance filing was considered but not supported by the Participants Committee at its May 3, 2019 meeting and filed on May 22 (*see* ER19-1951 above).

If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Jamie Blackburn (202-218-3905; jblackburn@daypitney.com).

- ***Orders 841/841-A*: Electric Storage Participation in RTO/ISO Markets (RM16-23; AD16-20)**

Order 841. On February 15, 2018, the FERC issued *Order 841*, which requires each RTO/ISO to revise its tariff "to establish a participation model consisting of market rules that, recognizing the physical and operational characteristics of electric storage resources, facilitates their participation in the RTO/ISO markets."[140] Additionally, each RTO/ISO must specify that the sale of electric energy from the RTO/ISO markets to an electric storage resource that the resource then resells back to those markets must be at the wholesale locational marginal price. *Order 841* became effective June 4, 2018. As previously reported, *Order*

[138] *Reform of Generator Interconnection Procedures and Agreements*, Order No. 845-A, 166 FERC ¶ 61,137 (Feb. 219, 2019).

[139] *Order 845-A* was published in the *Fed. Reg.* on Mar. 6, 2019 (Vol. 84, No. 44) pp. 8,156-8,185.

[140] The participation model must: (1) ensure that a resource using the participation model is eligible to provide all capacity, energy and ancillary services that the resource is technically capable of providing in the markets; (2) ensure that a resource using the participation model can be dispatched and can set the wholesale market clearing price as both a wholesale seller and wholesale buyer consistent with existing market rules that govern when a resource can set the wholesale price; (3) account for the physical and operational characteristics of electric storage resources through bidding parameters or other means; and (4) establish a minimum size requirement for participation in the RTO/ISO markets that does not exceed 100 kW.

841 did not adopt the *Storage NOPR's* proposed reforms related to DER aggregations. Instead, *Order 841* instituted a new rulemaking proceeding and technical conference (*see* RM18-9 above) to gather additional information to help the FERC determine what action to take with respect to DER aggregation. Requests for Clarification and/or Rehearing of *Order 841* were filed by CAISO, MISO, PJM, the AES Companies, AMP/APPA/NRECA, California Energy Storage Alliance, EEI, NARUC, PG&E, TAPS, and Xcel Energy Services.

Order 841-A. On May 16, The FERC issued *Order 841-A*[141] in which it denied the requests for rehearing and denied in part but granted in part the requests for clarification of *Order 841*. Specifically, the FERC clarified the following (requesting party in parentheses): (i) *Order 841* does not require an RTO/ISO to create and provide a capacity product that an RTO/ISO market does not otherwise offer (SPP); (ii) *Order 841* allows for flexibility in how RTOs/ISOs account for the physical and operational characteristics of electric storage resources, including State of Charge (PJM); (iii) the FERC will not dismiss as *per se* unreasonable any proposal to establish a non-facility-specific rate for wholesale distribution service to an electric storage resource for its charging (EEI); (iv) that an RTO/ISO could require verification from the host distribution utility that it is unable or unwilling to net wholesale demand from retail settlement before the RTO/ISO ceases to settle an electric storage resource's wholesale demand at the wholesale LMP (CAISO); and, finally, (v) that applicable transmission charges should apply when an electric storage resource is charging to resell energy at a later time. In addition the FERC modified § 35.28(g)(9)(i)(B) of the Commission's regulations to clarify that each RTO/ISO is required to allow resources using the participation model for electric storage resources to participate in the RTO/ISO markets as dispatchable resources, not that such resources are required to be dispatchable to use that participation model. *Order 841-A* was not challenged and is final and unappealable. *Order 841-A* will become effective August 21, 2019.[142] Reporting on this proceeding has now concluded.

- **NOPR: Data Collection for Analytics & Surveillance and MBR Purposes (RM16-17)**

The FERC's *Data Collection NOPR* remains pending. As previously reported, the FERC issued a July 21, 2016 NOPR, which superseded both its *Connected Entity NOPR* (RM15-23) and *Ownership NOPR* (RM16-3), proposing to collect certain data for analytics and surveillance purposes from market-based rate ("MBR") sellers and entities trading virtual products or holding FTRs and to change certain aspects of the substance and format of information submitted for MBR purposes.[143] The *Data Collection NOPR* presents substantial revisions from what the FERC proposed in the *Connected Entity NOPR*, and responds to the comments and concerns submitted by NEPOOL in that proceeding. Among other things, the changes proposed in the *Data NOPR* include: (i) a different set of filers; (ii) a reworked and substantially narrowed definition of Connected Entity; and (iii) a different submission process. With respect to the MBR program, the proposals include: (i) adopting certain changes to reduce and clarify the scope of ownership information that MBR sellers must provide; (ii) reducing the information required in asset appendices; and (iii) collecting currently-required MBR information and certain new information in a consolidated and streamlined manner. The FERC also proposes to eliminate MBR sellers' corporate organizational chart submission requirement adopted in *Order 816*. Comments on the *Data Collection NOPR* were due on or before September 19, 2016[144] and were filed by over 30 parties, including: APPA, Avangrid, Brookfield, EPSA, Macquarie/DC Energy/Emera Energy Services, NextEra, and NRG. The *Data Collection NOPR* remains pending.

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[141] *Elec. Storage Participation in Mkts. Operated by Regional Transmission Orgs. and Indep. Sys. Ops.*, Order No. 841, 167 FERC ¶ 61,154 (May 16, 2019) ("*Order 841*").

[142] *Order 841-A* was published in the *Fed. Reg.* on May 23, 2019 (Vol. 84, No. 100) pp. 23,902-23,927.

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

[144] The *Data Collection NOPR* was published in the *Fed. Reg.* on Aug. 4, 2016 (Vol. 81, No. 150) pp. 51,726-51,772.

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

On May 16, 2019, the FERC issued a NOPR proposing to incorporate by reference, with certain enumerated exceptions, the latest version (Version 003.2) of certain Standards for Business Practices and Communication Protocols for Public Utilities adopted by the Wholesale Electric Quadrant ("WEQ") of the North American Energy Standards Board ("NAESB").[145] The Version 003.2 Standards include NAESB's Version 003.1 revisions, which remain pending before the FERC following a July 2016 NOPR.[146] The FERC stated that comments already filed on the revisions made by NAESB in the WEQ Version 003.1 Standards will be given full consideration and need not be repeated in response to this NOPR. This NOPR invites comment on the latest revisions and corrections NAESB made in the WEQ Version 003.2 Standards. The FERC plans to act on all of the Version 003 revisions in this proceeding. NAESB's WEQ-023 Modeling Business Practice Standards, which concern technical issues affecting the calculation of Available Transfer Capability for wholesale electric transmission services, will be addressed separately. The WEQ Version 003.2 Standards include modifications and reservations to existing standards and newly developed standards made to support the short-term preemption process (WEQ-001-25) and the merger of like transmission reservations (WEQ-001-24) prescribed in the OASIS Suite of Standards. Other changes were made to support consistency with NERC Standards, to support the use of "market operator" as a separate role within the EIR, a NAESB managed industry tool, and on electronic tags (e-Tags), to revise certain Abbreviations, Acronyms, and Definitions of Terms in WEQ-000, and to make minor corrections. Comments on the *NAESB WEQ v. 003.2 Standards NOPR* are due on or before July 23, 2019.[147]

- **NOI: FERC's ROE Policy (PL19-4)**

On March 21, 2019, the FERC issued a notice of inquiry seeking information and views to help the Commission explore whether, and if so how, it should modify its policies concerning the determination of the return on equity ("ROE") to be used in designing jurisdictional rates charged by public utilities.[148] The Commission also seeks comment on whether any changes to its policies concerning public utility ROEs should be applied to interstate natural gas and oil pipelines. This NOI follows *Emera Maine*, which reversed *Opinion 531*, and seeks to engage interests beyond those represented in the *Emera Maine* proceeding (see EL11-66 *et al.* in Section I above). Initial comments are due June 26, 2019; reply comments, July 26, 2019.[149] A joint request by APPA, EEI and NRECA for an extension of time to submit reply comments was denied. Reply comments remain due on or before July 26, 2019. Thus far, initial comments have been submitted by the Institute for Energy Economics and Financial Analysis and four private citizens.

- **NOI: Electric Transmission Incentives Policy (PL19-3)**

Also on March 21, 2019, the FERC issued a notice of inquiry seeking comment on the scope and implementation of its electric transmission incentives regulations and policy pursuant to section 1241 of the Energy Policy Act of 2005 ("EPAct 2005"), codified in FPA Section 219, which directed the FERC to use transmission incentives to help ensure reliability and reduce the cost of delivered power by reducing transmission congestion.[150] Given the passage of time since Order 679 and the FERC's 2012 Incentives Policy Statement and the "significant developments in how transmission is planned, developed, operated, and

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

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

[147] The *ONAESB WEQ v. 003.2 NOPR* was published in the *Fed. Reg.* on May 24, 2019 (Vol. 84, No. 101) pp. 24,050-24,059.

[148] *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 166 FERC ¶ 61,207 (Mar. 21, 2019) ("*ROE Policy NOI*").

[149] The *ROE Policy NOI* was published in the *Fed. Reg.* on Mar. 28, 2019 (Vol. 84, No. 61) pp. 11,769-11,777.

[150] *Inquiry Regarding the Commission's Elec. Trans. Incentives Policy*, 166 FERC ¶ 61,208 (Mar. 21, 2019) ("*Electric Transmission Incentives Policy NOI*").

maintained," the FERC stated that "it is appropriate to seek comment … on the scope and implementation of the Commission's transmission incentives policy and on how the Commission should evaluate future requests for transmission incentives in a manner consistent with Congress's direction in section 219" and solicited comment on a variety of transmission incentives-related issues. Initial comments are due June 25, 2019.[151] On May 10, 2019, APPA, EEI and NRECA, in a motion covering both this and the FERC's ROE Policy proceeding, requested an extension of time to file reply comments. With respect to this proceeding, and unlike the ROE Policy proceeding, the FERC granted the motion to extend the reply period. According, reply comments will now be due on or before Aug 26, 2019. Initial comments remain due July 25, 2019. Thus far, one set of comments has been filed by the R Street Institute.

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

On April 19, 2018, the FERC announced its intention to revisit its approach under its 1999 Certificate Policy Statement to determine whether a proposed jurisdictional natural gas project is or will be required by the present or future public convenience and necessity, as that standard is established in NGA Section 7. Specifically, the NOI[152] seeks comments from interested parties on four broad issue categories: (1) project need, including whether precedent agreements are still the best demonstration of need; (2) exercise of eminent domain; (3) environmental impact evaluation (including climate change and upstream and downstream greenhouse gas emissions); and (4) the efficiency and effectiveness of the FERC certificate process. Pursuant to a May 23 order extending the comment deadline by 30 days,[153] comments were due on or before July 25, 2018. Literally thousands of individual and mass-mailed comments were filed. This matter remains pending before the FERC.

- **NOI: FERC's Policy for Recovery of Income Tax Costs & ROE Policies (PL17-1)**

On March 15, 2018, the FERC found that an impermissible double recovery results from granting a Master Limited Partnership pipeline ("MLP") both an income tax allowance and an ROE pursuant to the DCF methodology.[154] Accordingly, the FERC issued a revised policy statement that it will no longer permit an MLP to recover an income tax allowance in its cost of service. The finding follows an NOI[155] that sought comments regarding how to address any double recovery resulting from the FERC's income tax allowance and ROE policies in light of the D.C. Circuit's *United Airlines*[156] holding. The FERC indicated that it will address the application of *United Airlines* to non-MLP partnership forms as those issues arise in subsequent proceedings. The revised policy statement took effect on March 21, 2018. Requests for rehearing of the March 15 order were filed by the Dominion, Enable Mississippi River Transmission and Enable Gas Transmission, Enbridge and Spectra Energy Partners, EQT Midstream Partners, Kinder Morgan, Master Limited Partnership Association ("MLPA"), NGAA, SPPP, LP, Oil Pipe Lines, Plains Pipeline, Tallgrass Pipelines, and TransCanada. On July 18, the FERC issued its order on rehearing,[157] dismissing the requests for rehearing and clarification and providing guidance regarding the treatment of Accumulated Deferred Income Taxes ("ADIT") where the income tax allowance is eliminated from

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[151] The *Electric Transmission Incentives Policy NOI* was published in the *Fed. Reg.* on Mar. 28, 2019 (Vol. 84, No. 60) pp. 11,759-11,768.

[152] The NOI was published in the *Fed. Reg.* on Apr. 26, 2018 (Vol. 83, No. 80) pp. 18,020-18,032.

[153] *Certification of New Interstate Natural Gas Facilities*, 163 FERC ¶ 61,138 (May 23, 2018).

[154] *Inquiry Regarding the FERC's Policy for Recovery of Income Tax Costs*, 162 FERC ¶ 61,227 (Mar. 15, 2018), *order on reh'g*, 164 FERC ¶ 61,030 (July 18, 2018).

[155] *Inquiry Regarding the FERC's Policy for Recovery of Income Tax Costs,* 157 FERC ¶ 61,210 (Dec. 15, 2016).

[156] *United Airlines Inc. v. FERC*, 827 F.3d 122, 134, 136 (D.C. Cir. 2016) ("*United Airlines*") (holding that the FERC failed to demonstrate that there is no double recovery of taxes for a partnership pipeline as a result of the income tax allowance and ROE determined pursuant to the DCF methodology, and remanding the decisions to the FERC to develop a mechanism "for which the Commission can demonstrate that there is no double recovery" of partnership income tax costs). *Id.* at 137.

[157] *Inquiry Regarding the FERC's Policy for Recovery of Income Tax Costs*, 164 FERC ¶ 61,030 (July 18, 2018) ("*Order on Rehearing*").

cost-of-service rates under the FERC's post-*United Airlines* policy. On August 17, the MLPA requested clarification and/or reconsideration of the *Order on Rehearing*, which is pending before the FERC. On September 4, R. Gordon Gooch answered MLPA's August 17 pleading. Petitions for review were filed in the D.C. Circuit by Enable Mississippi River Transmission, LLC and Enable Gas Transmission, LLC, as well as by SFPP, L.P., in September 2018. Those appeals are pending in Case Nos. 18-1252, et al. in the D.C. Circuit.

XIII. Natural Gas Proceedings

For further information on any of the natural gas proceedings, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Jamie Blackburn (202-218-3905; jblackburn@daypitney.com).

- **Natural Gas-Related Enforcement Actions**

The FERC continues to closely monitor and enforce compliance with regulations governing open access transportation on interstate natural gas pipelines:

BP (IN13-15). On July 11, 2016, the FERC issued *Opinion 549*[158] affirming Judge Cintron's August 13, 2015 Initial Decision finding that BP America Inc., BP Corporation North America Inc., BP America Production Company, and BP Energy Company (collectively, "BP") violated Section 1c.1 of the Commission's regulations ("Anti-Manipulation Rule") and NGA Section 4A.[159] Specifically, after extensive discovery and hearing procedures, Judge Cintron found that BP's Texas team engaged in market manipulation by changing their trading patterns, between September 18, 2008 through the end of November 2008, in order to suppress next-day natural gas prices at the Houston Ship Channel ("HSC") trading point in order to benefit correspondingly long position at the Henry Hub trading point. The FERC agreed, finding that the "record shows that BP's trading practices during the Investigative Period were fraudulent or deceptive, undertaken with the requisite scienter, and carried out in connection with Commission-jurisdictional transactions."[160] Accordingly, the FERC assessed a ***$20.16 million civil penalty*** and required BP to ***disgorge $207,169*** in "unjust profits it received as a result of its manipulation of the Houston Ship Channel Gas Daily index." The $20.16 million civil penalty was at the top of the FERC's Penalty Guidelines range, reflecting increases for having had a prior adjudication within 5 years of the violation, and for BP's violation of a FERC order within 5 years of the scheme. BP's penalty was mitigated because it cooperated during the investigation, but BP received no deduction for its compliance program, or for self-reporting. The *BP Penalties Order* also denied BP's request for rehearing of the order establishing a hearing in this proceeding.[161] BP was directed to pay the civil penalty and disgorgement amount within 60 days of the *BP Penalties Order*. On August 10, 2016 BP requested rehearing of the *BP Penalties Order*. On September 8, the FERC issued a tolling order, affording it additional time to consider BP's request for rehearing of the *BP Penalties Order*, which remains pending.

On September 7, 2016, BP submitted a motion for modification of the *BP Penalties Order's* disgorgement directive because it cannot comply with the disgorgement directive as ordered. BP explained that the entity to which disgorgement was to be directed, the Texas Low Income Home Energy Assistance Program ("LIHEAP"), is not set up to receive or disburse amounts received from any person other than the Texas Legislature. In response, on September 12, 2016, the FERC stayed the disgorgement directive (until an order on BP's pending request for rehearing is issued), but indicated that interest will continue to accrue on unpaid monies during the pendency of the stay.[162]

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[158] *BP America Inc.*, Opinion No. 549, 156 FERC ¶ 61,031 (July 11, 2016) ("*BP Penalties Order*").

[159] *BP America Inc.,* 152 FERC ¶ 63,016 (Aug. 13, 2015) ("*BP Initial Decision*").

[160] *BP Penalties Order* at P 3.

[161] *BP America Inc.*, 147 FERC ¶ 61,130 (May 15, 2014) ("*BP Hearing Order*"), *reh'g denied,* 156 FERC ¶ 61,031 (July 11, 2016).

[162] *BP America Inc.*, 156 FERC ¶ 61,174 (Sep. 12, 2016) ("*Order Staying BP Disgorgement*").

BP moved, on December 11, 2017, to lodge, to reopen the proceeding, and to dismiss, or in the alternative, for reconsideration based on changes in the law it asserted are dispositive and that have occurred since BP filed its request for rehearing of the *BP Penalties Order*. FERC Staff asked for, and was granted, additional time, to January 25, 2018, to file its Answer to BP's December 11 motion. FERC Staff filed its answer on January 25, 2018, and revised that answer on January 31. On February 9, BP replied to FERC Staff's revised answer. This matter remains pending before the FERC.

Total Gas & Power North America, Inc. et al. (IN12-17). On April 28, 2016, the FERC issued a show cause order[163] 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.[164]

The FERC also directed TGPNA to show cause why it should not be required to disgorge unjust profits of ***$9.18 million***, plus interest; TGPNA, Tran and Hall to show cause why they should not be assessed civil penalties (TGPNA - ***$213.6 million***; Hall - ***$1 million*** (jointly and severally with TGPNA); and Tran - ***$2 million*** (jointly and severally with TGPNA)). In addition, the FERC directed TGPNA's parent company, Total, S.A. ("Total"), and TGPNA's affiliate, Total Gas & Power, Ltd. ("TGPL"), to show cause why they should not be held liable for TGPNA's, Hall's, and Tran's conduct, and be held jointly and severally liable for their disgorgement and civil penalties based on Total's and TGPL's significant control and authority over TGPNA's daily operations. Respondents filed their answer on July 12, 2016. OE Staff replied to Respondents' answer on September 23, 2016. Respondents answered OE's September 23 answer on January 17, 2017, and OE Staff responded to that answer on January 27, 2017. This matter remains pending before the FERC.

- **New England Pipeline Proceedings**
  The following New England pipeline projects are currently under construction or before the FERC:
  - ***Atlantic Bridge Project (CP16-9)***
    - 132,700 Dth/d of firm transportation to new and existing delivery points on the Algonquin system and 106,276 Dth/d of firm transportation service from Beverly, MA to various existing delivery points on the Maritimes & Northeast system.
    - 6.3 miles of replacement pipeline along Algonquin in NY and CT; new 7,700-horsepower compressor station in Weymouth, MA; more horsepower at existing compressor stations in CT and NY.
    - Seven firm shippers: Heritage Gas Limited, Maine Natural Gas Company, NSTAR Gas Company d/b/a Eversource Energy, Exelon Generation Company, LLC (as assignee and asset manager of Summit Natural Gas of Maine), Irving Oil Terminal Operations, Inc., New England NG Supply Limited, and Norwich Public Utilities.
    - Certificate of public convenience and necessity granted Jan. 25, 2017.[165]

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

[164] The allegations giving rise to the Total Show Cause Order were laid out in a September 21, 2015 FERC Staff Notice of Alleged Violations which summarized OE's case against the Respondents. Staff determined that the Respondents violated section 4A of the Natural Gas Act and the Commission's Anti-Manipulation Rule by devising and executing a scheme to manipulate the price of natural gas in the southwest United States between June 2009 and June 2012. Specifically, Staff alleged that the scheme involved making largely uneconomic trades for physical natural gas during bid-week designed to move indexed market prices in a way that benefited the company's related positions. Staff alleged that the West Desk implemented the bid-week scheme on at least 38 occasions during the period of interest, and that Tran and Hall each implemented the scheme and supervised and directed other traders in implementing the scheme.

[165] Order Issuing Certificate and Authorizing Abandonment, *Algonquin Gas Transmission LLC and Maritimes & Northeast Pipeline, LLC*, 158 FERC ¶ 61,061 (Jan. 25, 2017), *order denying stay*, 160 FERC ¶ 61,015 (2017), *reh'g denied,* 161 FERC ¶ 61,255 (Dec. 13, 2017) ("*Atlantic Bridge Project Order*").

- Certain facilities,[166] providing 40,000 out of the project's total capacity of 132,705 dekatherms per day of incremental firm transportation service, placed into service on November 1, 2017.[167] Remaining Project capacity will be available when the remaining Project facilities are placed into service following Director of OEP authorization.
- Algonquin files notice that construction of Salem Pike, Needham, Pine Hills and Plymouth meter and regulating stations began on April 2, 2018. Detailed information regarding construction activities can be found in the weekly construction reports filed in this docket.
- On February 16, 2018, Algonquin filed with the DC Circuit Court of Appeals, pursuant to NGA Section 19(d)(2), a petition for review of the MA DEP's failure to issue, condition, or deny a minor-source air permit for Algonquin's proposed natural gas compressor station in the Town of Weymouth, MA by the July 31, 2016 deadline established by the FERC. Algonquin seeks an order establishing a deadline for the MA DEP to issue, condition, or deny the permit.
- On May 31, the DC Circuit issued a *per curiam* order that holds this case in abeyance pending further order of the court.[168] The court based its order on the parties' representation that they have agreed on a schedule by which to resolve their dispute. The parties were directed to file status reports at 90-day intervals and to file motions to govern future proceedings within 30 days of respondents' final decision to issue, condition, or deny petitioner's permit application.
- Status reports have thus far been filed on August 24 and November 21, 2018, and February 20, 2019, each indicating that the case should continue to be held in abeyance. The next status report will be due in late May, 2019.
- On December 26, 2018, the FERC granted Algonquin a two-year extension of time, to January 25, 2021, to complete the Project.[169] In requesting the extension, Algonquin attributed the need for additional time to permitting delays for the Weymouth Compressor Station and ongoing construction of the Horizontal Directional Drill of the Taconic Parkway in New York. Requests for rehearing of the December 26 order were filed by two parties. On February 25, 2019, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending.

- ***Constitution Pipeline (CP13-499) and Wright Interconnection Project (CP13-502)***
  - Constitution Pipeline Company and Iroquois Gas Transmission (Wright Interconnection) concurrently filed for Section 7(c) certificates on June 13, 2013.
  - 650,000 Dth/d of firm capacity from Susquehanna County, PA (Marcellus Shale) through NY to Iroquois/Tennessee interconnection (Wright Interconnection).
  - New 122-mile interstate pipeline.
  - Two firm shippers: Cabot Oil & Gas and Southwestern Energy Services.
  - Final EIS completed on Oct 24, 2014.
  - Certificates of public convenience and necessity granted Dec 2, 2014.

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[166] The following facilities placed into service: Southeast Discharge Take-up and Relay (Fairfield County, CT); Modified Oxford Compressor Station (New Haven County, CT); Modified Chaplin Compressor Station (Windham County, CT); Modified Danbury (CT) Meter Station; and Modified Stony Point Compressor Station (Rockland County, NY).

[167] *Algonquin Gas Trans., LLC*, 158 FERC ¶ 61,061 (Oct. 27, 2017).

[168] *Algonquin Gas Trans. v. Mass. Dept. of Envtl. Protection*, Case No. 18-1045, DC Cir. (May 31, 2018).

[169] *Algonquin Gas Trans., LLC*, Docket No. CP16-9 (Dec. 26, 2018) (unpublished letter order), *reh'g requested*. Absent the extension, and pursuant to the Jan. 25, 2017 Certificate Order, the Project would otherwise have had to have been completed by Jan. 25, 2019.

- By letter order issued July 26, 2016, the Director of the Division of Pipeline Certificates (Director) granted Constitution's requested two-year extension of time to construct the project.
- Construction was expected to begin Spring 2016 (after final Federal Authorizations), but has been plagued by delays (see below).

- On April 22, 2016, New York State Department of Environmental Conservation (NY DEC) denied Constitution's application for a Section 401 permit under the Clean Water Act.
  - On August 18, 2017, the 2nd Circuit denied Constitution's petition for review of the NY DEC decision, concluding that (1) the court lacked jurisdiction over the Constitution's claims to the extent that they challenged the timeliness of the decision; and (2) the NY DEC acted within its statutory authority in denying the certification, and its denial was not arbitrary or capricious.
  - Constitution filed a petition for a writ of certiorari of the 2nd Circuit's decision at the United States Supreme Court in January 2018 alleging, among other things, that the State's denial of the Clean Water Act permit exceeded the state's authority, and interfered with FERC's exclusive jurisdiction. On April 30, 2018, the Supreme Court denied Constitution's petition, thereby letting stand the 2nd Circuit's ruling.
- On October 11, 2017, Constitution filed with the FERC a petition for declaratory order ("Petition") requesting that the FERC find that NY DEC waived its authority under section 401 of the Clean Water Act by failing to act within a "reasonable period of time." (CP18-5)
  - On January 11, 2018, the FERC denied Constitution's Petition.[170] Although noting that states and project sponsors that engage in repeated withdrawal and refiling of applications for water quality certifications are acting, in many cases, contrary to the public interest and to the spirit of the Clean Water Act by failing to provide reasonably expeditious state decisions, the FERC did not conclude that the practice violates the letter of the statute, found factually that Constitution gave the NY DEC new deadlines, and found that the record did not show that the NY DEC in any instance failed to act on Constitution's application for more than the outer time limit of one year.[171]
  - On February 12, 2018, Constitution Pipeline requested rehearing of the January 11, 2018 order. FERC denied Constitution's request for rehearing of the January 2018 order.[172] On September 14, 2018, Constitution filed a petition for review in the U.S. Court of Appeals for the D.C. Circuit.[173]
- On May 16, 2016, the New York Attorney General filed a complaint against Constitution at the FERC (CP13-499) seeking a stay of the December 2014 order granting the original certificates, as well as alleging violations of the order, the Natural Gas Act, and the Commission's own regulations due to acts and omissions associated with clear-cutting and other construction-related activities on the pipeline right of way in New York.
  - In July 2016, the FERC rejected the NY AG's filing as procedurally deficient, and declined to stay of the Certificate Order. The NY AG sought rehearing, and the Commission denied rehearing on November 22, 2016, noting again that the NY AG's complaint was still procedurally deficient.

[170] *Constitution Pipeline Co.*, 162 FERC ¶ 61,014 (Jan. 11, 2018), *reh'g requested*.

[171] *Id*. at P 23.

[172] *Constitution Pipeline Co., LLC*, 164 FERC ¶ 61,029 (2018) (September 2018 Waiver Rehearing Order).

[173] Constitution, Petition for Review in U.S. Court of Appeals for the D.C. Circuit, Docket No. CP18-5-000 (filed Sept. 14, 2018).

- Tree felling and site preparation continues, but the long-term status of the pipeline is currently unknown.
- On June 25, 2018, Constitution requested a further 2-year extension of the deadline to complete construction of its project, given the delays caused by the on-going fight over the water quality certification from the NYSDEC. Iroquois made a similar request on August 1, 2018. Constitution's request was opposed by several parties and Constitution answered some of the opposition pleadings. The FERC granted the requested two-year extension of time on November 5, 2018.[174]
- Rehearing of the November 5, 2018 order was requested by Halleran Landowners and a group of intervenors comprised of Catskill Mountainkeeper; Clean Air Council; Delaware-Otsego Audubon Society; Delaware Riverkeeper Network; Riverkeeper, Inc.; and Sierra Club ("Intervenors"). Constitution answered the requests for rehearing on December 21. The FERC issued a tolling order on December 21, affording it additional time to consider the requests for rehearing. This matter is pending before the FERC.

- **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.[175] Those orders have been challenged on appeal to the US Court of Appeals for the Second Circuit.
    - 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*.[176] 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,[177] 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,

[174] *Constitution Pipeline Co.*, 165 FERC ¶ 61,081 (Nov. 5, 2018), *reh'g requested*.

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

[176] *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).

[177] The DC Circuit has indicated that project applicants who believe that a state certifying agency has waived its authority under CWA section 401 to act on an application for a water quality certification must present evidence of waiver to the FERC. *Millennium Pipeline Co., L.L.C. v. Seggos*, 860 F.3d 696, 701 (D.C. Cir. 2017).

2017.[178] 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.[179] On February 2, 2019, the 2nd Circuit vacated the decision of the NY DEC and remanded the case with instructions for the NY DEC to more clearly articulate its basis for the denial and how that basis is connected to information in the existing administrative record. The matter is again before the NY DEC.
- On November 26, 2018, the Applicants filed a request at FERC for a 3- year extension of time, until February 3, 2022, to complete construction and to place the certificated facilities into service. The Applicants cited the fact that they "do not anticipate commencement of Project construction until early 2021 due to New York's continued legal actions and to time lines required for procurement of necessary pipe and compressor facility materials." The extension request remains pending.

XIV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XV. Federal Courts

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

- **FCM Pricing Rules Complaints (15-1071**, 16-1042) (consol.)**
  Underlying FERC Proceeding: EL14-7,[180] EL15-23[181]
  Petitioners: NEPGA, Exelon

On February 2, 2018, DC Circuit granted NEPGA's and Exelon's petitions for review of orders accepting the FCM's 7-year price lock-in (EL14-7) and capacity-carry-forward rules (EL15-23).[182] Finding that "the FERC failed to adequately explain why its rationale [for rejecting price lock-in and capacity carry forward rules] in PJM – which seems to foreclose signing off on a Tariff scheme like ISO-NE's – does not apply even more forcefully to the scheme it accepted in the Orders [appealed from]," the DC Circuit granted the Petitions and remanded the case to

[178] *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*").

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

[180] 150 FERC ¶ 61,064 (Jan. 30, 2015); 146 FERC ¶ 61,039 (Jan. 24, 2014).

[181] 154 FERC ¶ 61,005 (Jan. 7, 2016); 150 FERC ¶ 61,067 (Jan. 30, 2015).

[182] *New England Power Generators Assoc. v FERC*, 881 F.3d 202 (DC Cir. 2018).

the FERC for further proceedings in which the FERC, in order to accept the changes filed, must provide some analysis and explanation why it changed course. The remand is now pending before the FERC.

Other Federal Court Activity of Interest

- **PennEast Project (18-1128)**
  Underlying FERC Proceeding: CP15-558[183]
  Petitioners: NJ DEP, DE and Raritan Canal Commission, NJ Div. of Rate Counsel

Pending before the DC Circuit is an appeal of the FERC's orders granting certificates of public convenience and necessity to PennEast Pipeline Company, LLC ("PennEast")[184] for the construction and operation of a new 116-mile natural gas pipeline from Luzerne County, Pennsylvania, to Mercer County, New Jersey, along with three laterals extending off the mainline, a compression station, and appurtenant above ground facilities ("PennEast Project"). The FERC, as appellee, submitted its brief on March 21. Briefs supporting the FERC were filed by joint intervenors (ConEd and PennEast) and amicus curiae by INGAA. Since the last Report, parties submitted reply, final, and amicus briefs. In separate but related proceedings, the New Jersey Attorney General and several conservation groups have filed actions in federal district court in New Jersey seeking to limit PennEast's use of its NGA eminent domain authority. These matters remain pending.

[183] *PennEast Pipeline Co., LLC*, 162 FERC ¶ 61,053 (Jan. 19, 2018), *reh'g denied*, 163 FERC ¶ 61,159 (May 30, 2018).

[184] PennEast is a joint venture owned by Red Oak Enterprise Holdings, Inc., a subsidiary of AGL Resources Inc.; NJR Pipeline Company, a subsidiary of New Jersey Resources; SJI Midstream, LLC, a subsidiary of South Jersey Industries; UGI PennEast, LLC, a subsidiary of UGI Energy Services, LLC; and Spectra Energy Partners, LP.

INDEX
Status Report of Current Regulatory and Legal Proceedings as of June 21, 2019

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 Reported

VI. Schedule 20/21/22/23 Updates

VII. NEPOOL Agreement/Participants Agreement Amendments

VIII. Regional Reports

IX. Membership Filings

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

XI. Misc. Regional Interest

XII. Misc: Administrative & Rulemaking Proceedings

XIII. Natural Gas Proceedings

XIV. State Proceedings & Federal Legislative Proceedings

No Activity Reported

XV. Federal Courts

Highlights of the 2018 Assessment of the ISO New England Markets

Presented By:

David B. Patton, Ph.D.

Potomac Economics
External Market Monitor

June 25, 2019

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").
- This presentation summarizes our assessment of New England's wholesale power markets in 2018, focusing on:
  - ✓ Cross-market comparison of several key market outcomes and metrics;
  - ✓ The competitive performance of the markets;
  - ✓ Market issues related to out-of-merit uplift costs;
  - ✓ Fuel security in New England; and
  - ✓ Evaluation of the Pay-for-Performance framework.
- We also present recommendations for improving the ISO's markets.

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Summary of Market Outcomes

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Energy Markets

- The ISO-NE markets performed competitively in 2018.
  - ✓ Strong relationship between natural gas prices and energy prices
  - ✓ Energy offers in competitive electricity markets should track input costs.
- Weather conditions, include hot temperatures in the summer led to higher average load (2 percent) and peak load (9 percent) in the summer.
- The higher load and significantly higher natural gas prices (33 percent) in 2018 led to increases in:
  - ✓ Energy prices of 28-32 percent; and
  - ✓ NCPC Uplift of 35 percent.

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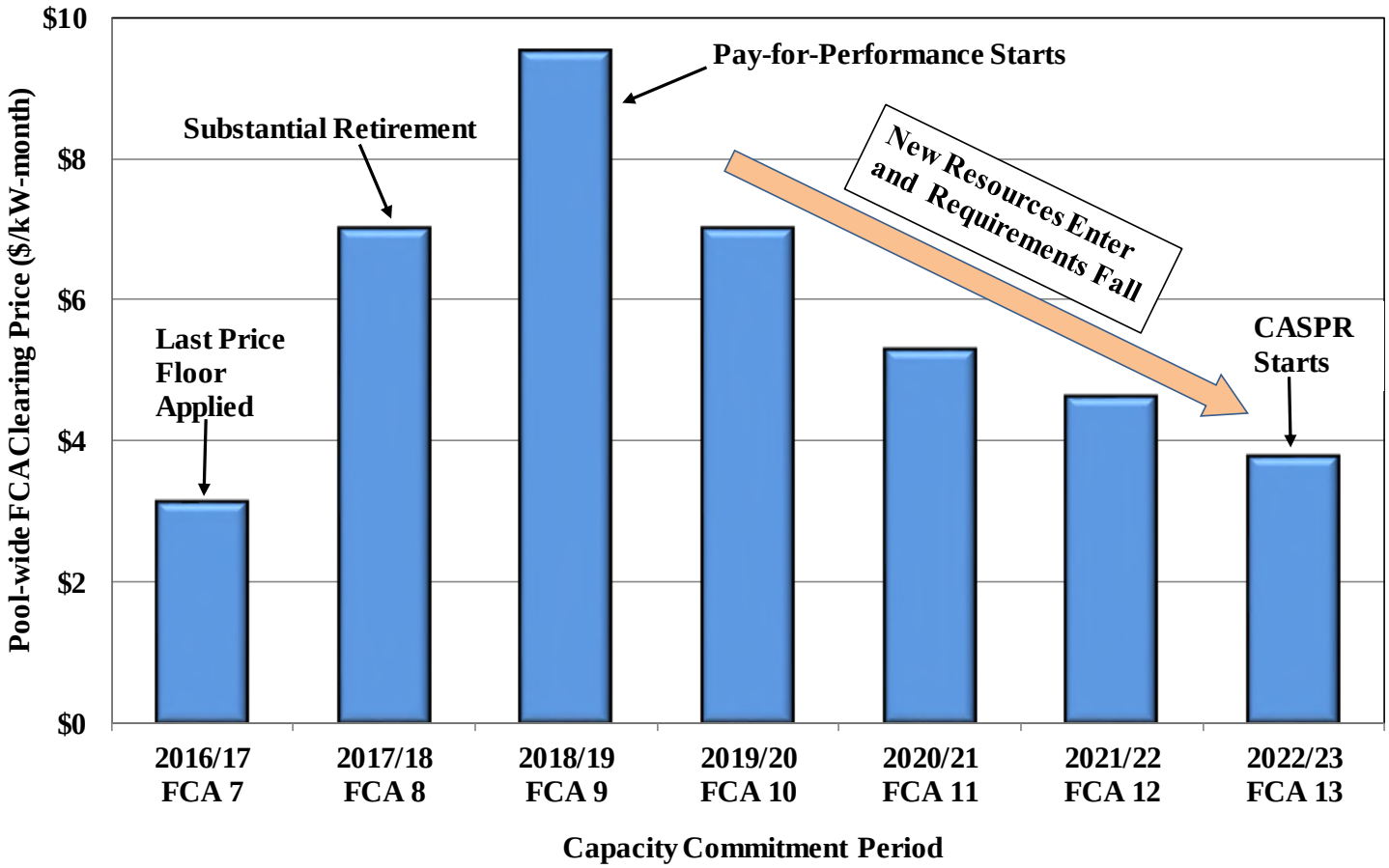
Capacity Market



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Cross-Market Comparison

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Cross-Market Comparison of Key Outcomes and Metrics

- Compared to most of other RTO markets, ISO-NE has:
  - ✓ The highest energy prices because of higher natural gas prices.
  - ✓ Far less congestion (10%-20% of other RTO markets) because of substantial transmission investments in the past decade.
    - – However, transmission service costs more than doubled the average rates in other RTO markets.
  - ✓ The highest net revenues that exceeded the CONE because of higher capacity revenues.
    - – However, this is not sustainable given falling capacity prices.
  - ✓ The best performing CTS implemented so far, partly because of the RTOs' decision not to impose charges to CTS transactions.
    - – However, forecast errors still limit the potential benefits.

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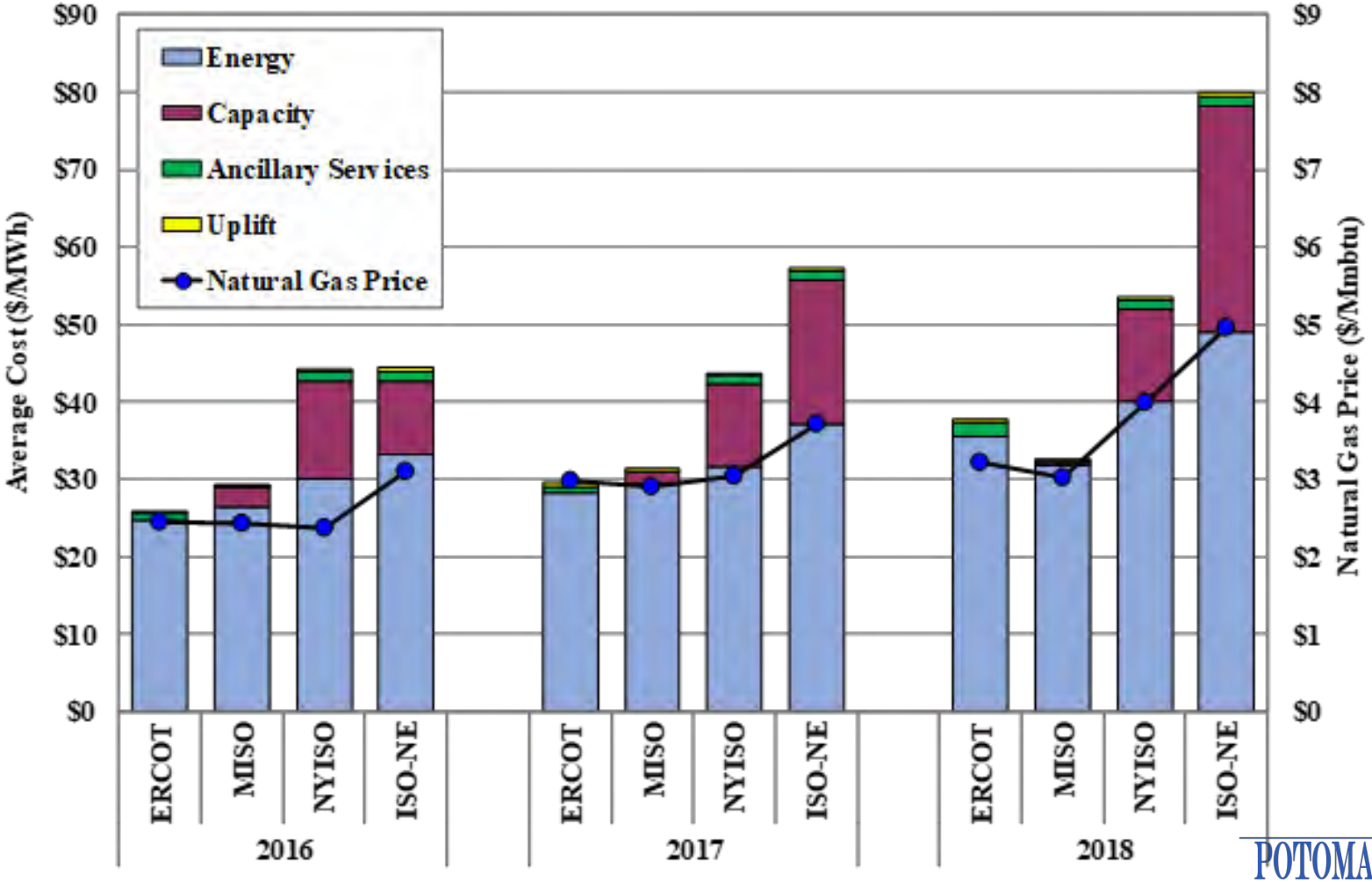
All-in Prices



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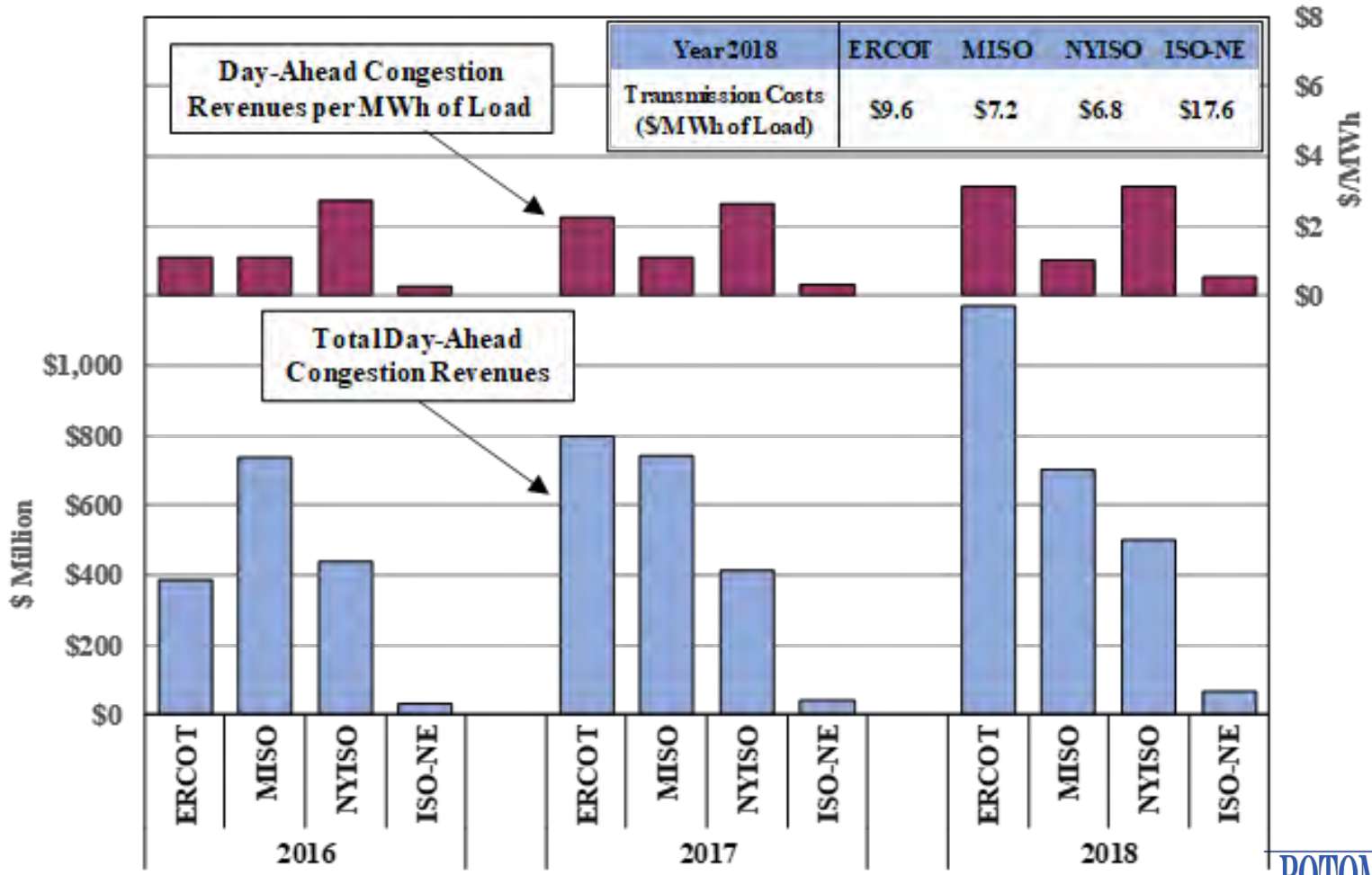
Congestion Costs



Year 2018	ERCOT	MISO	NYISO	ISO-NE
Transmission Costs ($/MWh of Load)	$9.6	$7.2	$6.8	$17.6

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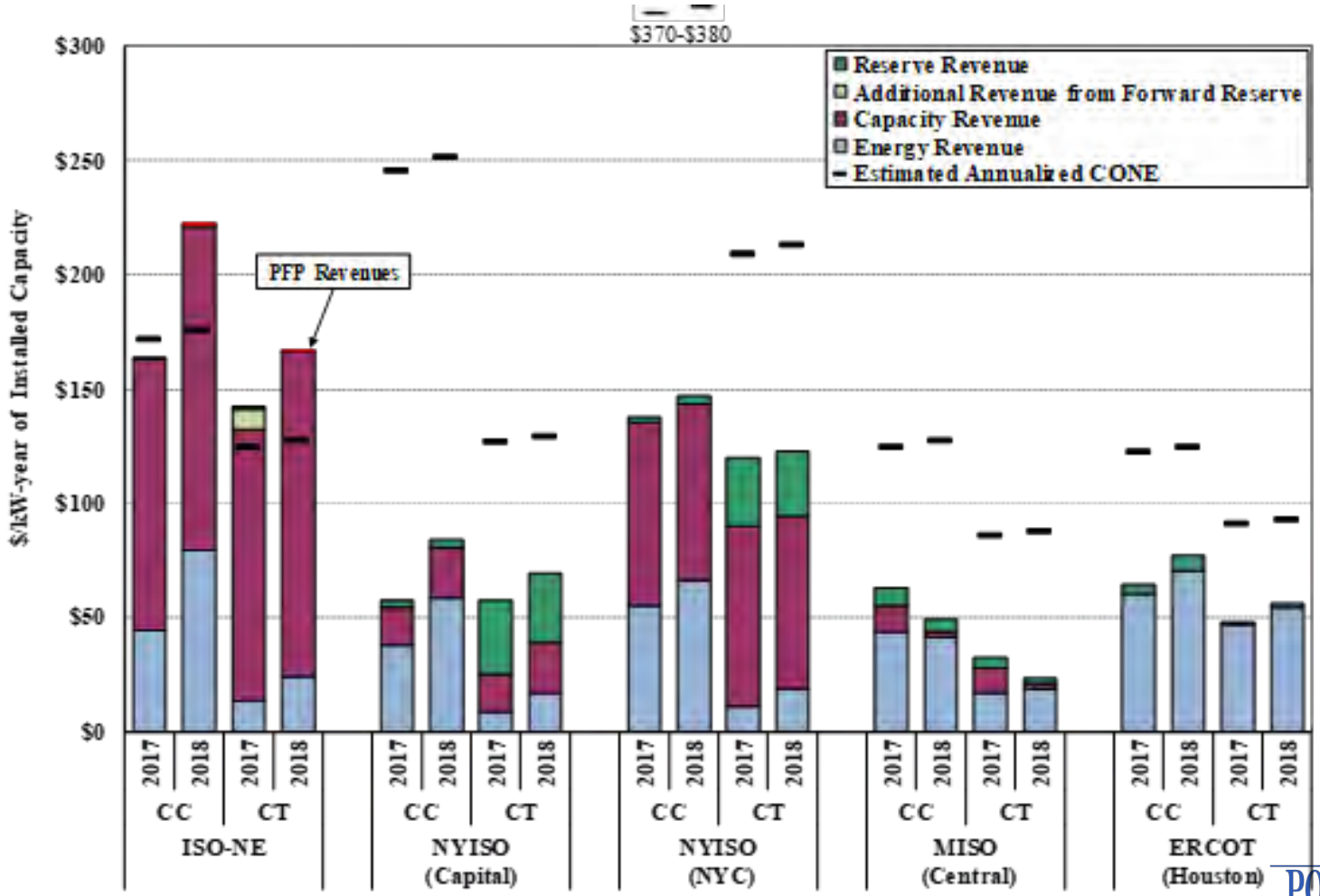
Net Revenues



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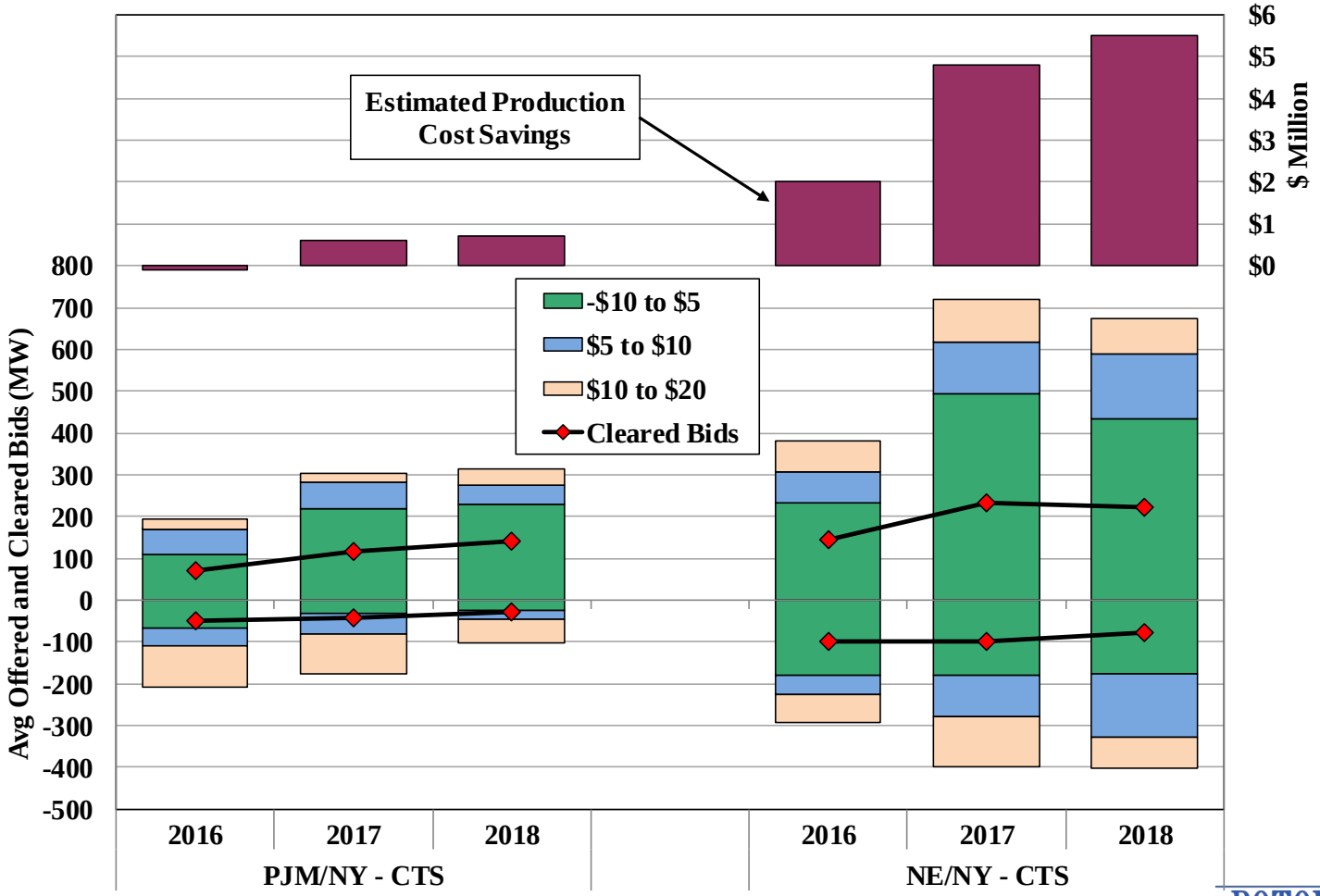
CTS Scheduling



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Market Competitiveness

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Evaluation of Market Competitiveness

- Our pivotal supplier analysis finds that market power concerns diminished greatly in Boston and market-wide in 2018.
- These changes are due to:
  - ✓ 1.5 GW of new CCs in the import-constrained areas;
  - ✓ Transmission upgrades in Boston; and
  - ✓ Lower market concentrations because of portfolio changes in several largest suppliers.

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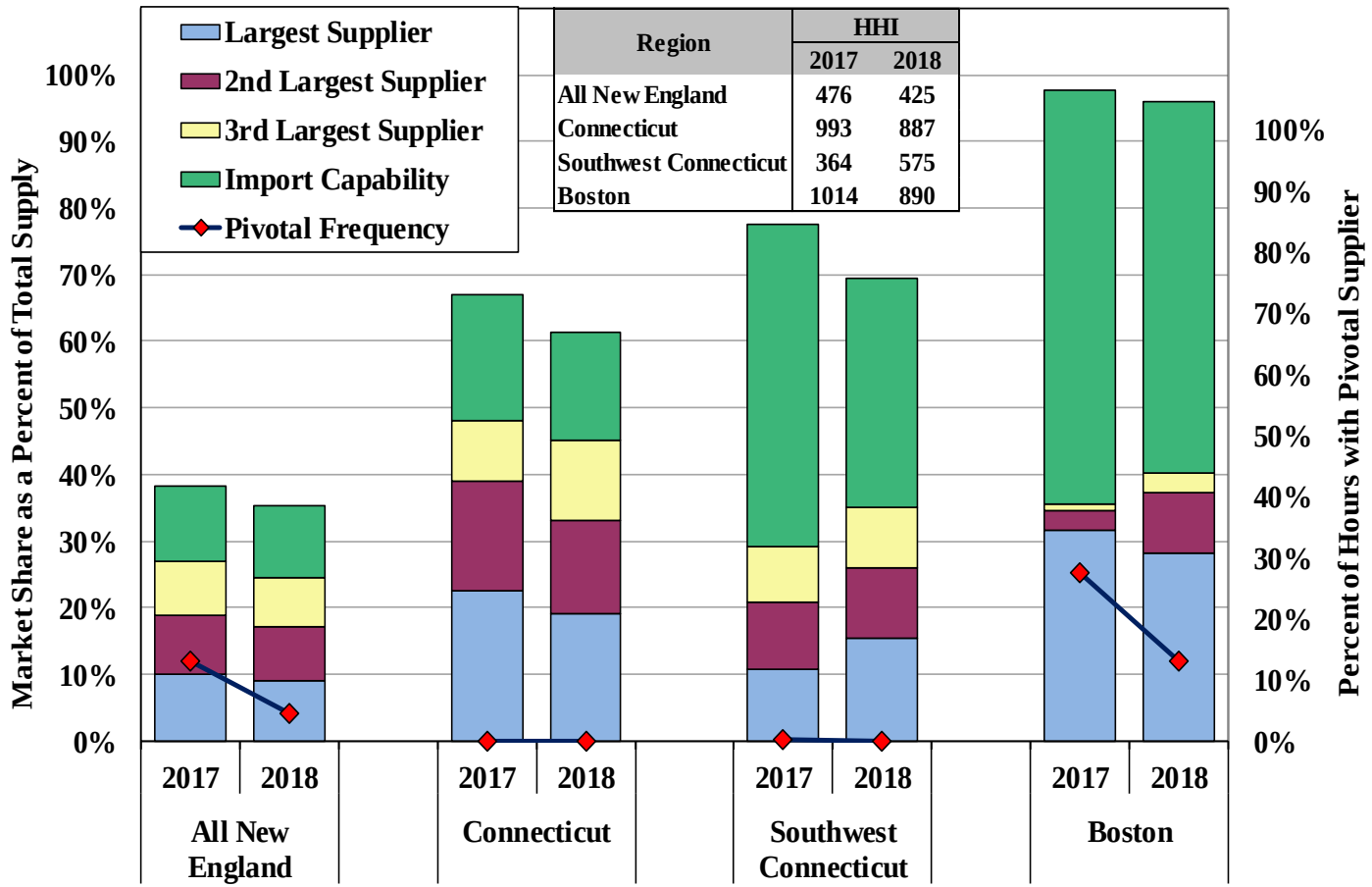
Market Power Mitigation



Region	HHI 2017	HHI 2018
All New England	476	425
Connecticut	993	887
Southwest Connecticut	364	575
Boston	1014	890

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Evaluation of Market Competitiveness

- Our analyses of market participant conduct indicated that the markets performed competitively:
  - ✓ Very little evidence of economic and physical withholding, or other forms of market power abuses or manipulation.
  - ✓ Mitigation was infrequent, effective in preventing the exercise of market power, and implemented consistent with Tariff.
- However, the mitigation measures may not have been fully effective for local reliability commitment.
  - ✓ Suppliers have the incentive to operate in a higher-cost mode and receive higher NCPC payment as a result.
  - ✓ We are encouraging the ISO to consider Tariff changes as needed to expand its authority to address this concern. (See Recommendation #2)

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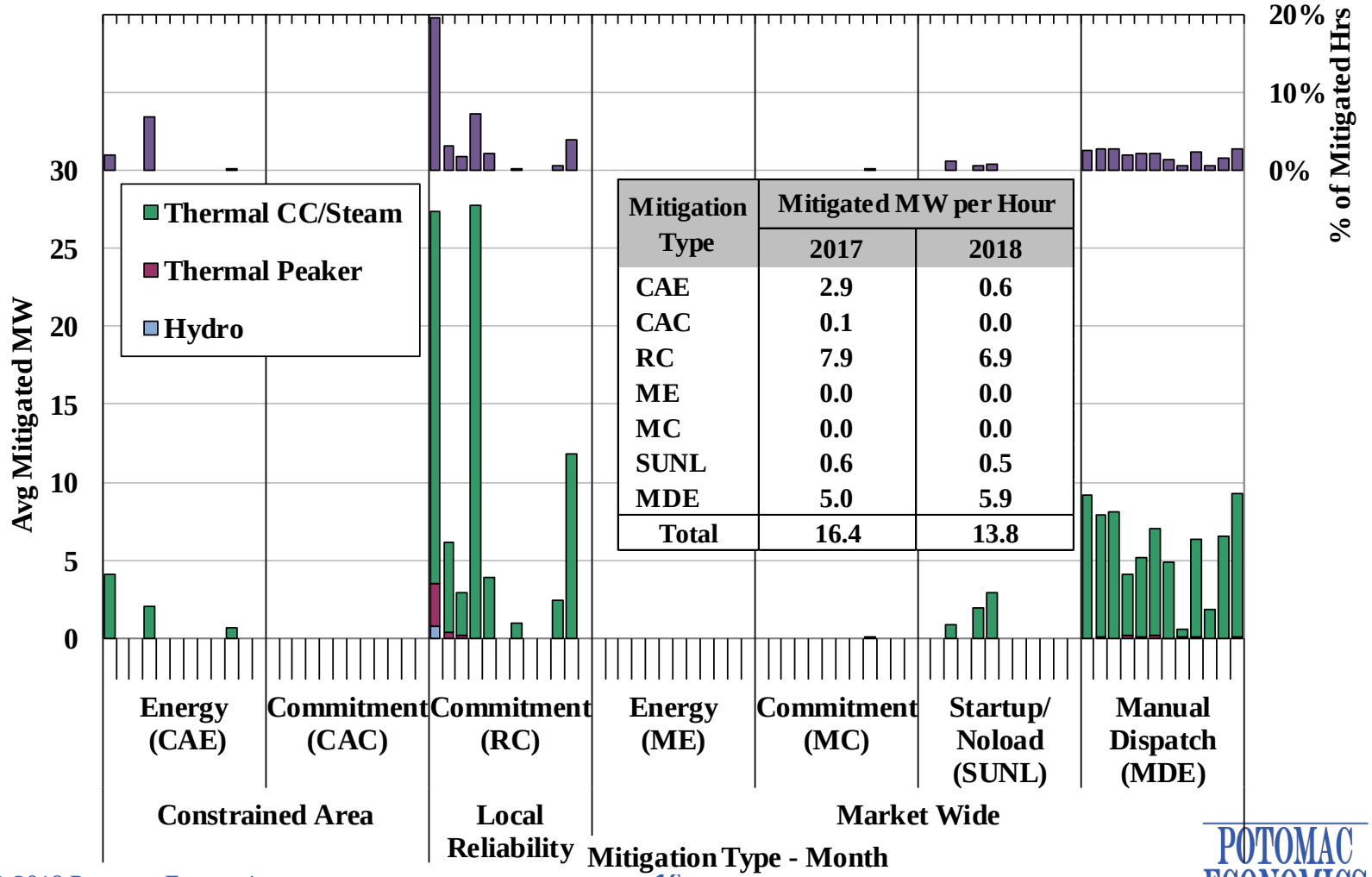
Market Power Mitigation



Mitigation Type	Mitigated MW per Hour	
	2017	2018
CAE	2.9	0.6
CAC	0.1	0.0
RC	7.9	6.9
ME	0.0	0.0
MC	0.0	0.0
SUNL	0.6	0.5
MDE	5.0	5.9
Total	16.4	13.8

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Operating Reserves and Uplift Costs

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Uplift Cost Comparison Across RTOs

- Uplift costs, particularly in the market-wide category, remain higher than other RTOs.

		ISO-NE			NYISO	MISO
		2016	2017	2018	2018	2018
Real-Time Uplift						
Total	**Local Reliability ($M)**	$1	$1	$4	$23	$3
	Market-Wide ($M)	$27	$23	$40	$19	$78
Per MWh of Load	**Local Reliability ($/MWh)**	$0.01	$0.01	$0.04	$0.14	$0.004
	Market-Wide ($/MWh)	$0.22	$0.19	$0.32	$0.12	$0.11
Day-Ahead Uplift						
Total	**Local Reliability ($M)**	$31	$15	$14	$31	$22
	Market-Wide ($M)	$13	$13	$12	$4	$17
Per MWh of Load	**Local Reliability ($/MWh)**	$0.25	$0.12	$0.11	$0.19	$0.03
	Market-Wide ($/MWh)	$0.10	$0.11	$0.10	$0.03	$0.03
Total Uplift						
Total	**Local Reliability ($M)**	$33	$16	$18	$54	$25
	Market-Wide ($M)	$40	$36	$52	$23	$95
Per MWh of Load	**Local Reliability ($/MWh)**	**$0.26**	**$0.13**	**$0.15**	**$0.33**	**$0.04**
	Market-Wide ($/MWh)	**$0.32**	**$0.29**	**$0.42**	**$0.14**	**$0.14**
	All Uplift ($/MWh)	**$0.58**	**$0.42**	**$0.57**	**$0.48**	**$0.17**

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Day-Ahead NCPC Costs and Reserve Markets

Market Issues

- Most of day-ahead NCPC charges occurred because of local and system-level reserve requirements that require committing additional resources are not currently priced.
- Of total day-ahead NCPC in 2018,
  - ✓ 47% was for the second contingency protection in local areas.
    - 60 percent of the commitments made by the DA commitment software for Boston would not have been needed if energy and reserves were to be co-optimized in the day-ahead market.
  - ✓ 30% was for the system-level 10-spinning reserve requirement.
    - Additional units were committed to meet this requirement in nearly 4,000 hours of the year.
    - These commitments lowered day-ahead energy prices by an estimated average of $1.0 - $1.5/MWh.

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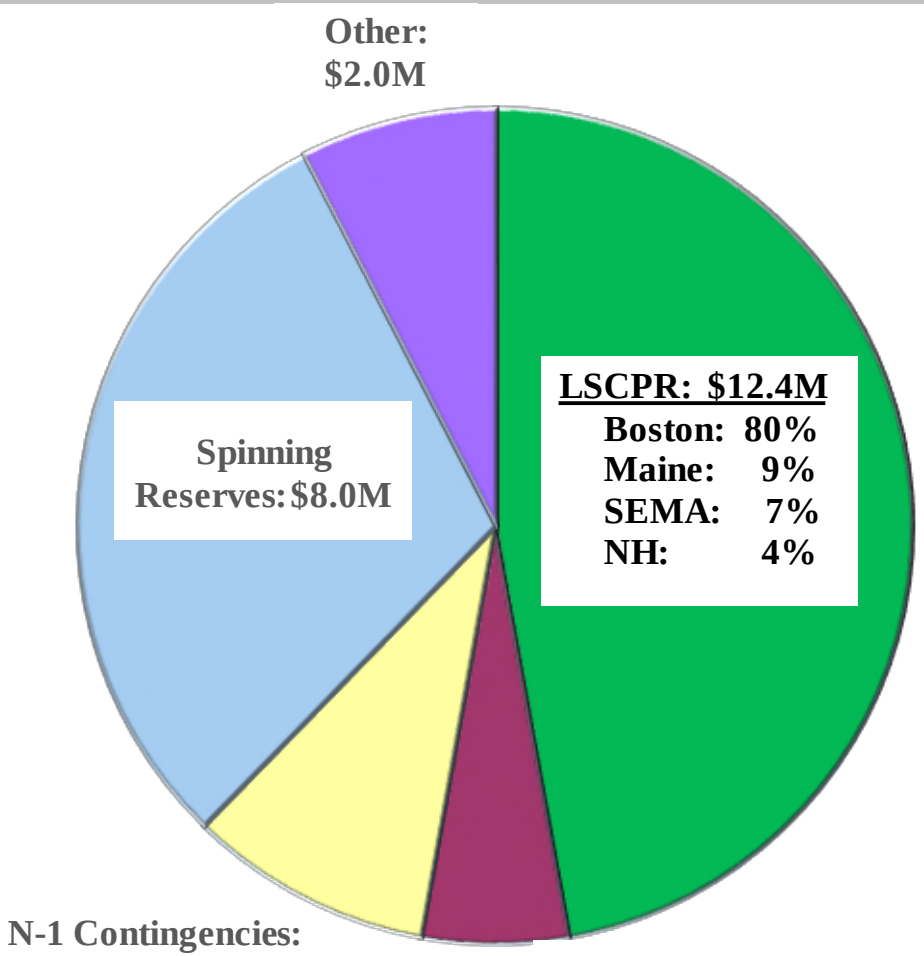
Day-Ahead NCPC Charges by Category 2018



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NCPC Costs and Day-Ahead Reserve Markets

Recommendations

- Introduce the day-ahead reserve markets that are co-optimized with day-ahead energy (see Recommendation #3), which would:
  - ✓ Allow the ISO to select the lowest-cost offers to simultaneously satisfy energy and reserve requirements and set prices efficiently;
  - ✓ Reduce day-ahead NCPC; and
  - ✓ Improve unit availability by scheduling reserves in a timeframe to allow suppliers to arrange fuel and staffing to be available for deployment.
- Eliminate the forward reserve market (see Recommendation #4), especially with the introduction of day-ahead reserve markets.
  - ✓ The forward reserve market has provided limited values and is largely redundant with the locational requirement in the FCM.
  - ✓ The forward procurements do not ensure that sufficient reserves will be available during the operating day.

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Real-Time NCPC and Allocations to Virtual Trading

Market Issues

- "RT deviations" caused only 14% of RT NCPC charges in 2018, but were allocated 40%.
- Virtual trades (part of RT deviations) were over-allocated RT NCPC charges, which were typically higher than in most other RTOs.
  - ✓ This has discouraged virtual trading, resulting in reduced liquidity in the DAM and less efficient resource commitment.

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	2016	1.3%	$1.70	2.0%	$1.94	$1.25
	2017	2.2%	$1.98	3.6%	$2.71	$0.81
	2018	2.7%	$1.10	4.5%	$2.69	$0.94
NYISO	2018	5.7%	$1.54	12.3%	-$0.35	< $0.1
MISO	2018	9.8%	-$0.31	9.8%	$1.90	$0.64

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Real-Time NCPC Charges by Category

Real-Time NCPC Category	Charges (Million $)	Share of RT NCPC
Local Reliability		
Local Second Contingency	$0.6	1%
Voltage Support	$0.4	1%
SCR	$0.6	1%
Multi-Turbine Portion	$2.7	6%
External Transactions	$2.7	6%
Market-Wide *Charged to RTLO*		
Generator Performance Audit	$1.4	3%
Dispatch LOC	$3.7	8%
Rapid Response OC	$4.0	9%
Resource Posturing	$10.1	23%
Market-Wide *Charged to RT Deviation*		
Fast Start Resources	$6.9	16%
Supplemental Commitment after DAM	$6.3	14%
Other	$4.4	10%
Total	$43.9	

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Real-Time NCPC and Allocations to Virtual Trading

Recommendations

- Modify the allocation of Economic NCPC charges to be more consistent with a "cost causation" principle.(see Recommendation #1)
  - ✓ This would largely involve not allocating NCPC costs to virtual load and other real-time deviations that do not cause it, which requires the ISO to:
    - Identify the reason for the economic NCPC (congestion vs capacity);
    - Quantify extent to which *net* "harming" deviations cause NCPC by:
      - Reducing total day-ahead generation schedules (e.g., virtual supply, unscheduled load); or
      - Reducing scheduled day-ahead flows over the constraint.
    - Allocate NCPC to harming deviations in proportion to their effect.
    - Allocate the residual to real-time load.

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Fuel Security in New England

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Winter Fuel Security

Market Issues

- In the first 13 FCAs, nearly 5 GW of nuclear, coal, and older steam turbine capacity has/will retire, and reliance on gas-fired capacity has increased.
  - ✓ Concerns heightened by potential retirement of Mystic and Distrigas.
- Our fuel security evaluation for a two-week severe winter period shows:
  - ✓ In the Baseline Scenario, very high utilization of oil inventory capacity and LNG import capability would be needed.
  - ✓ In the Pipeline Contingency Scenario or in a scenario with major reductions in availability, load shedding would occur.
- ISO's OFSA and Mystic Retirement Study also found tight fuel supply margins that could result in load shedding in winters of 2022/23 and 2023/24.

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Fuel Security Outlook for Winter 2022/23

- ISO is currently designing rules to incentivize suppliers to acquire the fuel necessary to maintain reliability during periods of gas scarcity.
  - ✓ In the long term, these changes should provide incentives for investment in fuel-secure new resources and maintenance of existing resources.
  - ✓ In the short term, these changes should improve incentives to procure fuel and fully utilize the existing resources.
- ISO's assumptions in the OFSA model are very conservative about oil tank replenishment rates and dispatch order, and are based on past experience.
- ISO reran the OFSA model with modifications to the following two default assumptions:
  - ✓ Light oil units (i.e., combined cycles) are always dispatched before heavy oil units (i.e., older steam turbines).
  - ✓ Oil-fired and dual-fuel generators will not fill their oil tanks to capacity before each winter or fully utilize refueling capacity during the winter.

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Fuel Security Outlook for Winter 2022/23

Results

- Market design changes will substantially affect reliability.
  - ✓ Modifying dispatch order will eliminate all hours of load shedding and 10-minute reserve depletion.
  - ✓ Frequent refills would eliminate even 30-minute reserve depletion.
- System would be far more reliable even under contingency scenarios with significant reductions in supply.
  - ✓ None of the extraordinary contingencies considered would result in load shedding hours.
- Battery storage resources can provide considerable flexibility to the system, but they are energy limited and have very little fuel security value.

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Fuel Security Analysis with Modified Assumptions (Winter 2022/23)

Scenario Description	No.	Assumptions				Results (Hrs)		
		New Entry and Retirements	Dispatch Order	Oil Tank Refills	LNG (bcf/d)	30 Min Res Depletion	10 Min Res Depletion (< 700MW)	Load Shedding
ISO Ref + Updated Resource Mix	[1]	FCA-13 New Entry/ Retirements	ISO default	1.25	0.8	138	12	2
[1] + Modified Dispatch	[2]	FCA-13 New Entry/ Retirements	CCs after ST units	1.25	0.8	24	0	0
[2] + Modified Refills (*EMM Reference*)	[3]	FCA-13 New Entry/ Retirements	CCs after ST units	Heavy - Unlimited Light - 2	0.8	0	0	0
[3] with Batteries Replacing a ST	[4]	FCA-13 New Entry/ Retirements + 600MW of batteries in place of ST	CCs after ST units	Heavy - Unlimited Light - 2	0.8	2	0	0
Contingencies								
EMM Ref [3] - Millstone outage	[5]	FCA-13 New Entry/ Retirements - Millstone out for 14 peak days	CCs after ST units	Heavy - Unlimited Light - 1	0.8	36	0	0
EMM Ref [3] - Pipeline outage	[6]	FCA-13 New Entry/ Retirements - 1.2 bcf/d gas unavailable for 14 peak days	CCs after ST units	Heavy - Unlimited Light - 1	0.8	57	1	0
EMM Ref [3] - Canaport outage	[7]	FCA-13 New Entry/ Retirements - Canaport out for 14 peak days	CCs after ST units	Heavy - Unlimited Light - 1	0.4	14	0	0

Fuel Security Outlook for Winter 2024/25

Results

- No significant fuel security issues in 2024/25 with modified dispatch order and replenishment assumptions.
- Impact of retiring the Mystic and Distrigas facilities would depend on the response from other sources of supply.
  - ✓ If the volume of LNG imports through the other two import terminals rose from 0.4 to 0.8 Bcf/day, reserve shortages would become much less frequent.
  - ✓ Increasing LNG to 0.8 Bcf/day, replacing slightly over half the supply lost from Mystic + Distrigas, eliminates 10-minute reserve depletion to 700 MW.
  - ✓ Other risks to consider upon retirement of Mystic and Distrigas:
    - Impact of large supply-side contingencies
    - Rate of entry of low fuel security resources (e.g. batteries) and exit of fuel-secure resources
- Developing a market mechanism would provide valuable incentives, and can reduce or eliminate the reliability impact of losing Mystic and Distrigas.

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Fuel Security Analysis with Retirement of the Mystic and Distrigas Facilities (Winter 2024/25)

Scenario Description	No.	Assumptions			Results (Hrs)		
		New Entry and Retirements	Oil Tank Refills	LNG (bcf/d)	30 Min Res Depletion	10 Min Res Depletion (< 700MW)	Load Shedding
EMM Reference 2024/25	[1]	FCA-13 New Entry/ Retirements	Heavy - Unlimited Light - 2	0.8	0	0	0
Sensitivities on LNG Injection for Mystic 8 and 9 and Distrigas LNG Retirement Scenario							
LNG Sensitivity #1 (Low Injection)	[2]	FCA-13 New Entry/ Retirements - Mystic 8 and 9 + Distrigas LNG retired	Heavy - Unlimited Light - 2	0.4	216	2	0
LNG Sensitivity #2	[3]			0.5	146	2	0
LNG Sensitivity #3	[4]			0.6	95	0	0
LNG Sensitivity #4	[5]			0.7	52	0	0
LNG Sensitivity #5 (High Injection)	[6]			0.8	23	0	0

Evaluation of the Pay-for-Performance Framework

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First Pay-for-Performance Event

- Pay-for-Performance rule became effective on June 1, 2018.
- The first such event occurred on September 3 primarily due to unexpectedly high load and significant forced outages and derates.
- PFP incentives were in effect during the reserve shortage at a rate of $2,000/MWh.
  - ✓ Steam turbine units accounted for $22 million in PFP charges.
    - These units were not economic in the day-ahead market.
    - They could not respond to this real-time event because of long lead times.
  - ✓ Combined-cycle units accounted for almost $9 million in charges and more than $14 million in performance payments.
    - Although forced outages were the primary driver, several units were simply not committed in the day-ahead market.
    - Some units responded by self-scheduling in real-time but came online after the shortage ended.
  - ✓ Imports received performance payments of nearly $15 million, roughly half of which was paid to importers with no capacity obligations.

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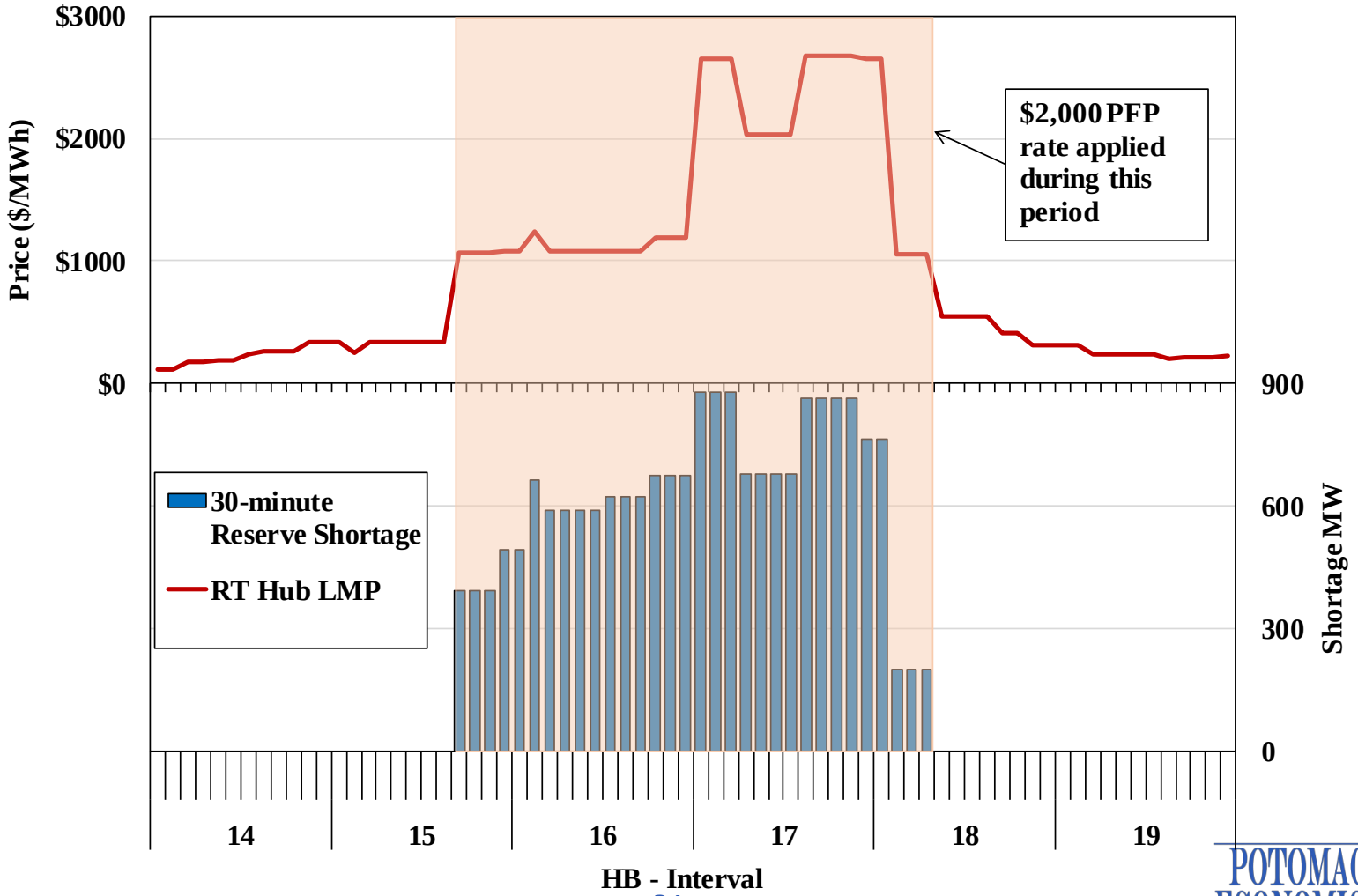
Pay-for-Performance Event
September 3, 2018



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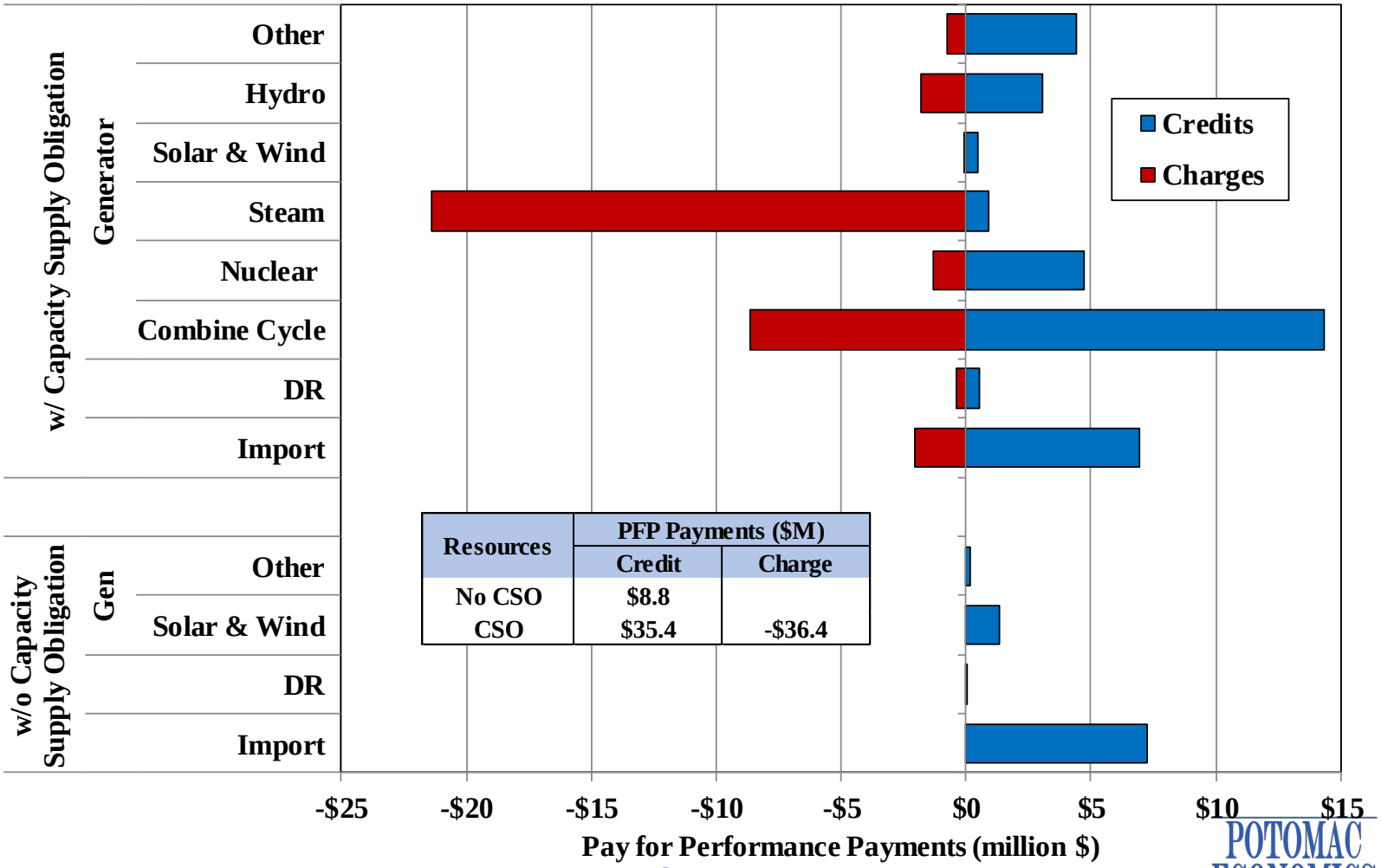
Pay-for-Performance Credits & Charges
September 3, 2018



Resources	PFP Payments ($M)	
	Credit	Charge
No CSO	$8.8	
CSO	$35.4	-$36.4

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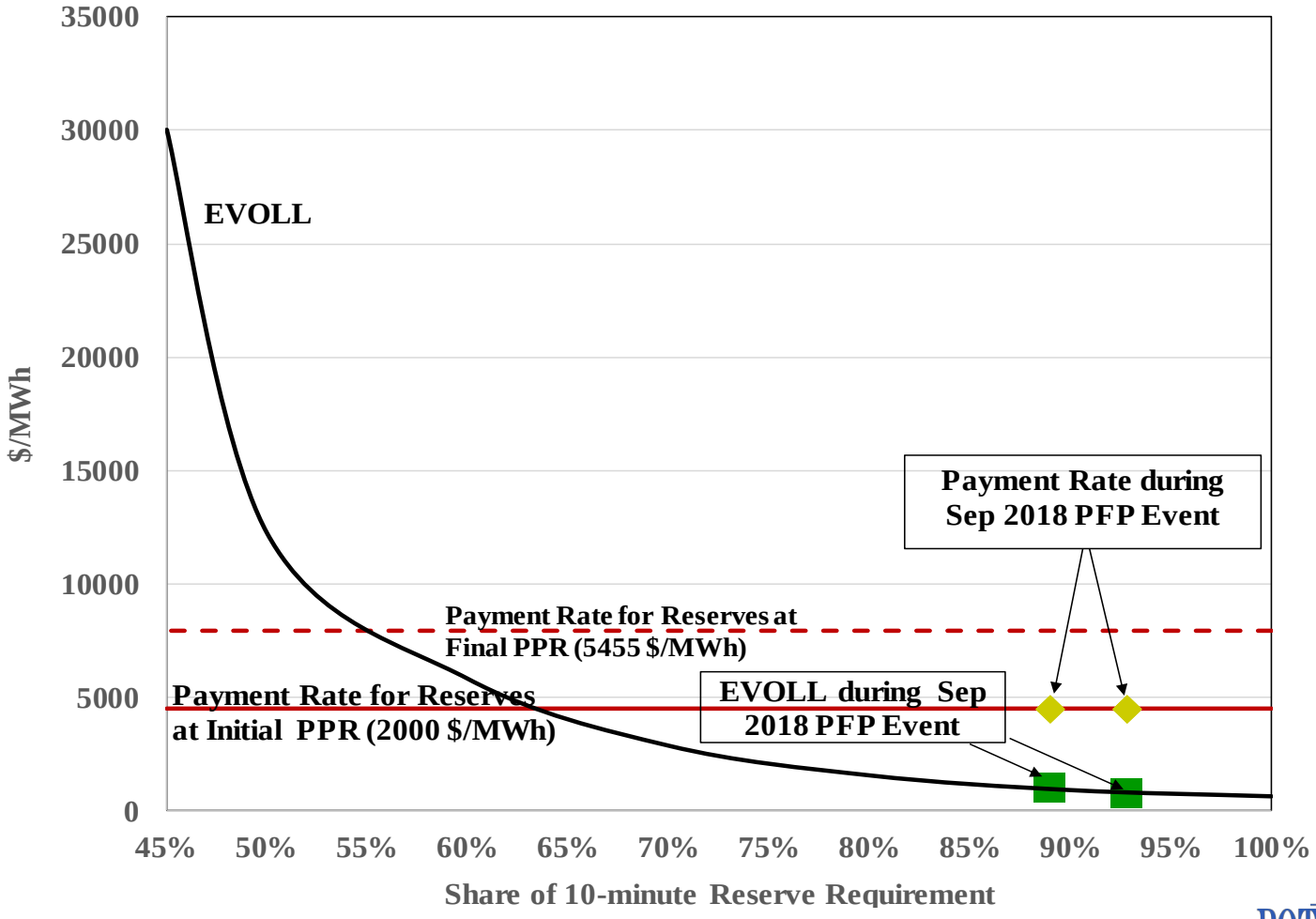
Evaluation of Pay-for-Performance Pricing

- Total incentives provided by the real-time market and the PFP were large.
  - ✓ Settlements exceeded $4700 although reserves were above 60% of requirements.
- Efficient prices during reserve shortages are key to establishing economic signals. Efficient shortage pricing should:
  - ✓ Reflect the marginal reliability value of reserves given the shortage level;
  - ✓ Depend on the risk of potential supply contingencies, including multiple simultaneous contingencies; and
  - ✓ Rise gradually as the reserve shortage increases and have no artificial discontinuities that can lead to excessively volatile outcomes.
- The marginal reliability value of reserves equals expected value of lost load ("EVOLL"), which is a product of: (a) value of lost load, and (b) the probability of losing load.
- We compared EVOLL at various reserve levels to actual settlements by:
  - ✓ assuming a high VOLL of $30,000 per MWh; and
  - ✓ using a Monte Carlo analysis based on random forced outages of generation.

POTOMAC ECONOMICS

Comparison of Reserve Prices to EVOLL during PFP Events



POTOMAC ECONOMICS

Evaluation of Pay-for-Performance Pricing

Results

- EVOLL during the event ranged from $700 to $1,000 per MWh, far lower than the actual rate of compensation of $3000 to $4700 per MWh.
- EVOLL curve has a convex shape to it.
  - ✓ Current rate of compensation far higher than efficient price levels during shallow shortages and much lower during deep shortages.
  - ✓ PFP framework over-compensates flexible resources that resolve transient and shallow shortages, and under-compensates resources that resolve more serious shortages.

Recommendation

- Modify the PPR to rise with the reserve shortage level, and
- Do not implement the remaining planned increase in the payment rate.

POTOMAC ECONOMICS

Incentives for Energy Storage Resources under Pay-for-Performance

Market Issues

- Interest in ESRs has grown quickly in recent years, but valuing capacity, energy and operating reserves is challenging.
- We evaluate the reliability value of a 2-hour ESRs and find that such units are likely to be over-compensated.
- FCM rules allow ESRs to qualify 100 percent of their capability, but PFP rules do not provide sufficient discipline in qualifying their capacity.
  - ✓ ESRs can provide reserves for extended periods of time, unless they are required to discharge.
  - ✓ Simulations of a system at one-day-in-ten-year standard indicate that load shedding constitutes only *two percent* of reserve shortage hours.
  - ✓ Therefore, risk of PFP penalties may not be significant relative to the potential upside from higher capacity revenue.
- ESRs are likely to find it profitable to sell 100 percent of their capacity.

POTOMAC ECONOMICS

Incentives for Energy Storage Resources under Pay-for-Performance

Results

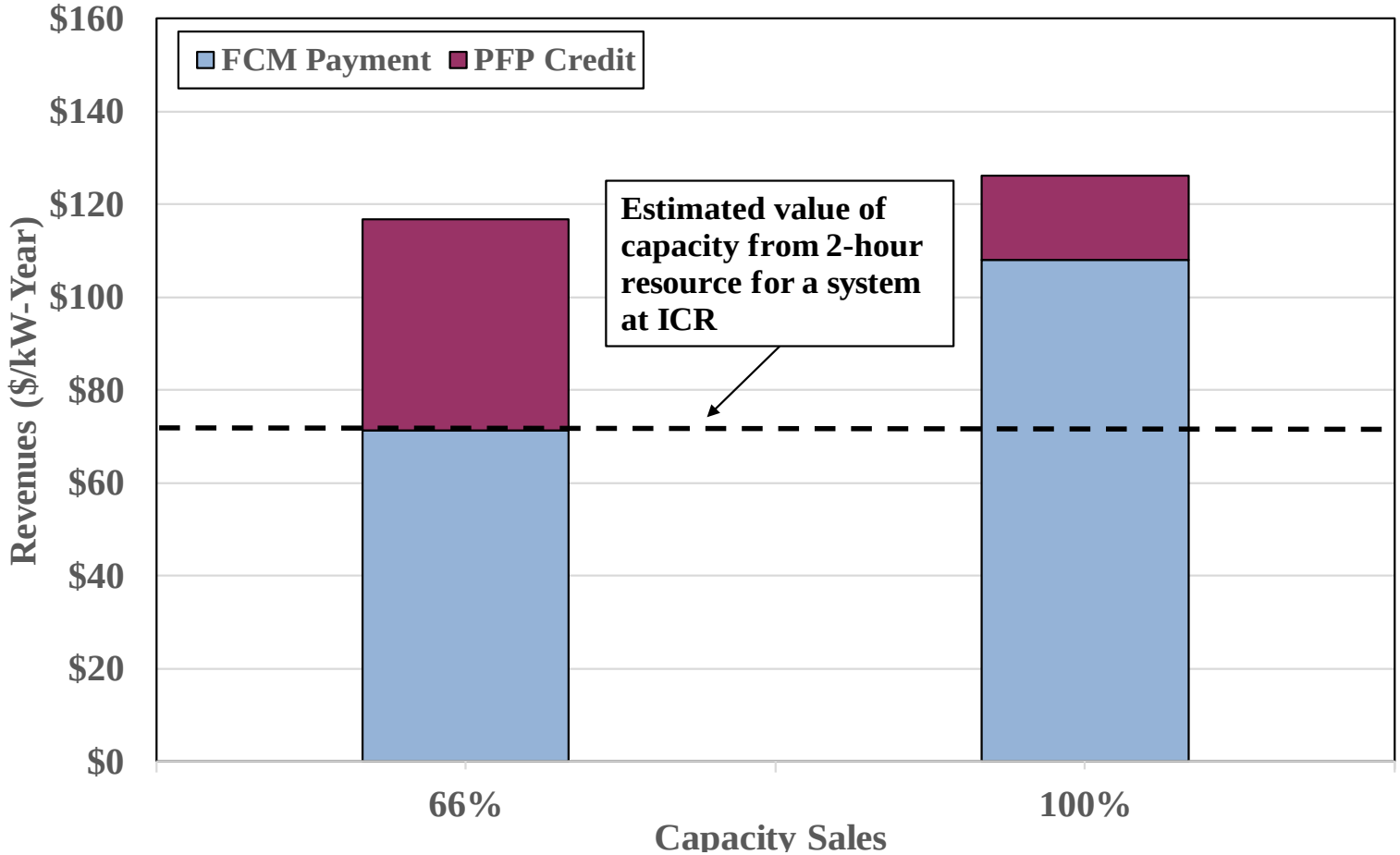
- GE-MARS simulations indicate that capacity value of a 2-hour ESR was 63 to 68 percent with 500 MW penetration.
- 2-hour ESRs would receive 117 percent of the compensation of a capacity supplier with average performance.
- ESRs are over-valued in capacity market because:
  - ✓ 2-hour ESRs are far less valuable for preventing load shedding than the average conventional resource.
  - ✓ ESRs are likely to have high rates of availability during reserve shortages and comparatively lower availability during load shedding.
- PFP construct over-compensates ESRs because PPR is the same for shallow and deep shortages, although the EVOLL is low for shallow shortages.

Recommendation

- Consider modifying the capacity compensation of energy limited resources to be consistent with the reliability value.

POTOMAC ECONOMICS

Breakdown of Revenues for a 2-Hour Battery Resource



POTOMAC ECONOMICS

Full List of Recommendations

POTOMAC ECONOMICS

List of Recommendations

Recommendation	Wholesale Mkt Plan	High Benefit[1]	Feasible in ST[2]
Reliability Commitments and NCPC Allocation			
1. Modify allocation of "Economic" NCPC charges to make it consistent with a "cost causation" principle.	✓		✓
2. Utilize the lowest-cost fuel and/or configuration for multi-unit generators when committed for local reliability.			✓
Reserve Markets			
3. Introduce day-ahead operating reserve markets that are co-optimized with the day-ahead energy market.	✓	✓	
4. Eliminate the forward reserve market.			✓
External Transactions			
5. Pursue improvements to the price forecasting that is the basis for Coordinated Transaction Scheduling with NYISO.		✓	✓

Notes:

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

POTOMAC ECONOMICS

List of Recommendations (cont.)

Recommendation	Wholesale Mkt Plan	High Benefit[1]	Feasible in ST[2]
Capacity Market			
6. Replace the descending clock auction with a sealed-bid auction to improve competition in the FCA.			✓
7. Modify the PPR to rise with the reserve shortage level, and not implement the remaining planned increase in the payment rate.			
8. Consider modifying the capacity compensation of energy limited resources to be consistent with the reliability value.			
9. Improve the MOPR by: a) eliminating performance payment eligibility for units subject to the MOPR, b) capping the Minimum Offer Price at net CONE, and c) exempting competitive private investment from the MOPR.			✓

POTOMAC ECONOMICS

2018 Assessment of the ISO New England Electricity Markets

POTOMAC ECONOMICS

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External Market Monitor
for ISO-NE

June 2019

TABLE OF CONTENTS

List of Figures

List of Tables

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 2018 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 2018.

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.

[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 forward 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.

The ISO Internal Market Monitor ("IMM") produces an annual report that provides an excellent summary and discussion of the market outcomes and trends during the year.[2] The IMM Annual Report shows:

- Energy prices rose 28 to 32 percent from 2017 to 2018 as natural gas prices increased by 33 percent. This correlation is consistent with our findings that the market performed competitively because energy offers in competitive electricity markets should track input costs.
- Load rose 2 percent from 2017, attributable to hot and humid summer weather conditions in 2018. Nonetheless, load levels have been low in recent years because of the increase in energy efficiency programs and the strong growth in behind-the-meter solar generation.
- Capacity prices rose to $9.55 per kW-month in the 2018/2019 Capacity Commitment Period ("CCP"), reaching its peak level in the short-term. Prices will start to fall in FCA 10 (the 2019/2020 CCP) and drop to $3.80 in FCA 13 (the 2022/2023 CCP) as the system returns to a higher surplus capacity with the entry of new resources.
- Pay-for-performance ("PFP") rules became effective in June 2018. The first and only PFP event in 2018 occurred on September 3, driven by unexpected high load and forced generation loss. This event led to $44 million of credits to over-performers and $36 million of charges to under-performers.

The IMM report provides detailed discussion of these trends and other market results and issues that arose in the ISO-NE markets during 2018. This report is intended to complement the IMM report, comparing key market outcomes with other RTO markets and focusing on key market design and competitive issues. Hence, this report includes:

- A cross-market comparison of several key market outcomes and metrics to illuminate how market conditions and market performance vary in ISO-NE from other RTOs;
- A competitive assessment of the energy and ancillary services markets;

[2] See ISO New England's Internal Market Monitor 2017 Annual Markets Report, available at https://www.iso-ne.com/markets-operations/market-monitoring-mitigation/internal-monitor.

- Evaluation of how the ISO's proposed market design reforms should address most of the fuel security challenges facing New England;
- Review of the efficiency of compensation to resources through the PFP framework, including an evaluation of the first-ever PFP event; and
- Analysis of market issues related to out-of-market uplift costs.

Cross-Market Comparison of Key Market Outcomes

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

- ISO-NE has generally exhibited the highest energy prices of the RTO markets. The relatively high energy costs in New England are primarily attributable to the higher natural gas prices in this region.
- ISO-NE experiences far less congestion than any of other RTOs. On a per MWh of load basis, congestion levels in New England are one-tenth to one-fifth of the congestion levels in other RTO markets. This reflects the substantial transmission investments made over the past decade, which has resulted in transmission service cost of nearly $18 per MWh – well more than double the average rates in other RTO markets.
- Net revenues provided by the ISO-NE markets exceeded the entry costs for both new combustion turbines or combined cycle resources in 2018, while none of the other RTO markets produced similar investment incentives. This was largely due to high revenues from the ISO-NE's capacity market, which, however, may not sustain given falling capacity prices in the coming years.
- The CTS process between New England and New York has improved over time because of a) improvements in price forecasts and b) increased CTS bid liquidity that has benefitted from the RTOs' decision not to impose charges on these transactions. These two factors have led to substantial production cost savings. It is by far the best performing CTS that has been implemented to date (CTS process have been implemented between PJM and both NYISO and MISO). However, forecast errors are still limit the potential benefits of CTS and the ISO should continue to pursue improvements.

Competitive Assessment

Based on our evaluation of the ISO-NE's wholesale electricity markets contained in this report, we find that the markets performed competitively in 2018. Our pivotal supplier analysis suggests that structural market power concerns diminished noticeably in Boston and in all New England in 2018, driven largely by the new market entry of roughly 1.5 GW of combined cycle generating capacity in the import-constrained areas, portfolio changes in the largest suppliers, and transmission upgrades in Boston. 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 2018.

In addition, 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.

To ensure competitive offers are not mitigated, it is important for generators to proactively request reference level adjustments when they experience input cost changes due to fuel price volatility and/or fuel quantity limitations. In addition, the ISO implemented a procedure before the 2018/19 winter to allow opportunity costs resulting from fuel limitations in reference levels for oil-fired and dual-fuel generators. This enhancement should lead to more efficient scheduling of energy-limited resources. We will continue monitor its effectiveness particularly under prolonged severe winter weather conditions.

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, the suppliers have the incentive to operate in a higher-cost mode and receive higher NCPC payments as a result. Hence, we recommend the ISO consider tariff changes as needed to expand its authority to address this concern.

Addressing Winter Fuel Security Concerns

New England has become increasingly reliant on natural gas and vulnerable to disruptions in fuel supplies to the region in recent years. Nearly 5 GW of new fuel-efficient conventional generation has been built and a comparable amount of nuclear, coal-fired, and older steam turbine capacity has retired in the first 13 Forward Capacity Auctions. The New England market has lacked the necessary elements to address reliability needs that are driven by fuel limitations. These concerns were heightened after the ISO entered into an out-of-market contract to prevent the retirement of the Mystic generating station.

The ISO developed the Operational Fuel Security Assessment ("OFSA") model to evaluate the planning reliability needs of New England with explicit consideration of fuel supply limitations. This model is innovative, but we are concerned that it relies on some assumptions that are overly conservative by assuming that the market will not respond with additional fuel supplies under shortage conditions. Consequently, the OFSA model may indicate the need for additional installed capacity to address a fuel security issue that could be fully resolved through market design enhancements that motivate resource owners to procure additional fuel supplies for existing generation.

The market design enhancements being developed by the ISO will compensate resources for holding inventories during tight fuel conditions and provide incentives that help the region conserve fuel supplies. We worked with the ISO to run scenarios of the OFSA model to evaluate how these market design enhancements are likely to affect reliability, since market incentives will improve the operation of the system and decisions by suppliers, including:

- Deploying heavy oil units ahead of light oil units (when light oil units have more limited oil inventories) – Under tight fuel supply conditions, an efficient market design will motivate units with limited inventories to conserve their remaining fuel, leading units with larger inventories to be deployed first—even if the units with limited inventories are more fuel efficient (which is usually the case in New England);
- More frequent refilling of oil inventories – Under tight fuel supply conditions, an efficient market design will motivate dual fuel units to maintain higher inventories and refuel more frequently; and
- Higher utilization of existing LNG-import capacity – If a major fuel source is lost, an efficient market design will induce generators and natural gas shippers to contract with LNG-importers to increase supplies to one of the other two terminals in the region, utilizing up to 50 percent of their remaining surplus capacity.

We evaluated two timeframes, one before the Mystic Units retire and one after the Mystic retention contract expires and the units are assumed to have retired:

- Winter 2022/23 – This is the Capacity Commitment Period ("CCP") corresponding to the Forward Capacity Auction that was held in February 2019 (i.e., FCA 13). We found that the improved deployment and fuel procurement asumptions would effectively address New England's reliability needs—even under severe weather and large supply contingency scenarios. These results highlight the reliability improvements that are possible with better incentives in the day-ahead and real-time markets without any capacity additions.
- Winter 2024/25 – This is the first winter after the Mystic retention contract expires (i.e., FCA 15). The improvements described above would fully address the fuel security concerns after the Mystic units and Distrigas LNG retire. However, the region might still experience reliability issues during severe winter weather in certain extreme supply contingency scenarios.

These results underscore the importance of the market enhancements being developed by the ISO. These enhancements will provide strong incentives for resources to procure fuel necessary to maintain reliability under peak conditions, and increase the utilization of existing equipment for storing oil and importing LNG. This would not only likely eliminate reliability issues during extreme winter conditions, but also enable the ISO to maintain system reliability after the loss of a critical resource, such as the Millstone nuclear plant, a major pipeline, or an LNG import

facility. In the longer-term, the ISO's market enhancements will shift investment incentives towards resource entry and retirement decisions that help maintain reliability after the potential retirements of the Mystic units and the Distrigas LNG facility.

Incentives of Pay-for-Performance Rules

The Pay-for-Performance ("PFP") rules were implemented to enhance incentives for suppliers to perform when they are needed the most. This report summarizes market outcomes during the first PFP event since the rules became effective on June 1, 2018. We evaluate the efficiency of compensation received by suppliers during the event compared to the risk of not serving load and the value of lost load. We also identify a misalignment between the compensation of short-duration energy limited resources and their value to the system during reserve shortage events.

The first PFP event in New England occurred for two-and-a-half hours on September 3, during which the ISO ran short of 30-minute reserves by up to 880 MW. The shortage resulted primarily from unexpectedly high load (actual load exceeded the forecast by roughly 2.5 GW) and the sudden loss of generation (roughly 1.4 GW), leading the ISO to cut exports, make emergency purchases, and activate Price-Responsive Demand. The combination of shortage pricing and PFP incentives led to marginal compensation rates of up to $4700 per MWh. Performance of individual resources was generally consistent with expectations as steam turbines accounted for the majority of PFP charges, since most had not been economic to commit in the day-ahead market, while other resource categories generally received more credits than charges with fast-start units and importers doing particularly well.

PPR versus the Marginal Value of Reserves

During reserve shortages, prices should rise gradually with the severity of the shortage, reflecting the marginal reliability value of reserves given the size of the shortage and the risk of potential supply contingencies. The marginal reliability value of reserves is the expected value of lost load ("EVOLL") that will not be served if the available reserves are reduced by 1 MW. Assuming a relatively high value of lost load ("VOLL") of $30,000 per MWh, we estimated the EVOLL based on the probability of contingencies that could result in load shedding during the event on September 3. The EVOLL is important because it reflects efficient shortage compensation for resources that are producing energy and/or reserves.

We estimate that the EVOLL ranged from $700 to $1000 per MWh during the event, far lower than the marginal rate of compensation under the PPR, which ranged from $3000 to $4700 per MWh. However, we find that for reserve shortages of more than 1.2 GW, the EVOLL would quickly rise above $4700 per MWh up to the assumed VOLL of $30,000 per MWh. This illustrates the deficiencies with the current PPR, that the single payment rate is: a) well above a reasonable estimate of the average EVOLL, and b) fixed regardless of the magnitude of the shortage. Hence, we recommend the ISO modify the PPR to rise with the reserve shortage level,

and not to implement the remaining planned increase in the payment rate. These changes would enhance price formation during reserve shortage events and encourage more efficient short and long-run decisions by suppliers.

Incentives for Energy Storage Resources

Interest in battery storage and other energy limited resources has grown quickly in recent years as policy-makers look for non-fossil fuel options for integrating intermittent renewables. However, these resources present special challenges for valuing capacity and energy and operating reserves under shortage conditions. We evaluate the reliability value of a 2-hour battery storage resource and find that such units are likely to be over-compensated under the current capacity market rules, including the PFP compensation provisions. This is concerning as policy-makers and developers prepare to invest heavily in this technology in the coming years.

The FCM rules allow battery storage resources to qualify for 100 percent of their maximum capability, but these resources have significant duration limitations that make them less valuable than most conventional resources when the system is near load shedding conditions. Furthermore, the flexibility of these resources make them likely to perform better under the PFP provisions than most resources during mild to moderate reserve shortage conditions. As discussed above, the marginal compensation rate is far higher than the EVOLL during such reserve shortages, leading battery storage resources to be greatly over-compensated.

We performed a Monte Carlo analysis to estimate the reliability value of a 2-hour battery storage resource for avoiding load shedding and the compensation it would receive in the capacity market. This found that a 2-hour battery storage resource would:

- Have 66 percent of the value of an average conventional resource for avoiding load shedding, and
- Receive 117 percent of the total capacity compensation of an average conventional resource.

This over-compensation cannot be fixed by reducing the qualified capacity of these resources to an appropriate level (e.g., 66 percent), since this reduction would be offset by a significant increase in the PFP credit. As stated earlier, a graduated PPR that rises with the magnitude of the reserve shortage would largely correct this over-compensation to these resources. Hence, to correct the over-compensation of energy storage resources, we recommend that the ISO: (a) reduce the qualified capacity of these resources before the FCA, and (b) adopt a graduated PPR that rises with the magnitude of the reserve shortage.

Capacity Market Design Enhancements

The purpose of the capacity market is to provide a market mechanism for ensuring that sufficient resources are procured to satisfy the planning reliability requirements of New England. The forward capacity market coordinates decisions to retire or mothball older resources with decisions to invest in new generation, demand response, and transmission. We evaluate potential market design improvements to facilitate competition in the auction and to enhance incentives for timely delivery of new resources.

Addressing Issues in the Minimum Offer Price Rules

The purpose of the minimum offer price rule ("MOPR") is to prevent uneconomic subsidized resources from artificially depressing market prices. This is important because these price effects will undermine the market's ability to facilitate efficient long-term investment and retirement decisions by market participants. However, MOPR can also potentially interfere with competitive investment or artificially increase prices. Hence, it is important to ensure that MOPR is effective in addressing uneconomic entry while not interfering with economic entry. Based on our evaluation of the MOPR in previous years, we've identified three issues that we recommend the ISO address to improve its MOPR.

Conforming the MOPR to the Pay-for-Performance Framework

Under the PFP rules, most of the value of capacity in the long-run will be embedded in the performance payments. Participants that sell capacity are essentially engaging in a forward sale of the expected performance payments (they receive the capacity payment up front in exchange for not receiving the performance later when they are running during a shortage). However, resources that do not sell capacity can earn comparable revenues by simply running during shortages and receiving the performance payments. In other words, a supplier has two options:

- Sell capacity and commit to producing energy during shortages, relinquishing the performance payments in could have earned; or
- Do not sell capacity and earn the performance payment by producing during the shortages.

In equilibrium, these two options should produce the same expected revenues. MOPR precludes an uneconomic entrant from selling capacity (choosing the first option), which simply means that the mitigated resource would default to option 2. Because option 2 should provide substantial expected revenues, the MOPR will not likely be an effective deterrent under the PFP framework. In addition, an uneconomic entrant will be able to depress capacity prices without selling capacity because it will lower the expected number of shortage hours. Therefore, we recommend the ISO make units that were mitigated under the MOPR ineligible to receive performance payments.

Competitive Entry Exemption

As noted above, the MOPR is intended to address uneconomic subsidized new resources that can artificially increase supply and depress prices. However, the current rules apply to all investment in new resources, including private investment in resources that are receiving no out-of-market subsidies. To the extent that the MOPR affects the offer prices submitted for such resources, it will interfere with competitive market-based investment. Mitigation is not reasonable in these cases because no private entity in New England is likely large enough to benefit from privately funding an uneconomic resource in order to lower prices.

Additionally, there are a number of reasons why a competitive developer may offer less than a default Net CONE level. For example, it may have more optimistic assumptions regarding future fuel prices, electricity prices, capacity prices, or other factors that affect the profitability of the resource. Given risks related to the timing and legal hurdles associated with new investment, it may be efficient for a competitive supplier to incur substantial costs and proceed significantly down the path of developing the unit before offering in the FCA. In this case, it may be competitive to offer at a relatively low level, which would not indicate an attempt to exercise buyer-side market power and would be harmful to mitigate.

Other RTOs have addressed this concern by implementing a "competitive entry exemption" to prevent the MOPR from interfering with private market-based investment.[3] Essentially, such a provision would exempt a new resource from the MOPR if it demonstrates that it is not receiving any direct subsidies or indirect subsidies via contract with a regulated entity. FERC's recent deficiency letter regarding an offer of a new resource in FCA 13 highlights the value of this exemption.[4]

Capping the Minimum Offer Price

The MOPR is intended to prevent prices from reflecting artificial supply surpluses caused by uneconomic entry. There is no economic justification, however, for mitigating new resources when surplus capacity is zero or negative (i.e., when new resources are needed to satisfy the system's planning resource needs). In this case, a competitive and efficient market would facilitate entry at price close to the net CONE, and no price above this level can reasonably be considered depressed. Likewise, it is unreasonable for the MOPR to raise prices substantially above net CONE. Unfortunately, this outcome would occur under ISO-NE's current MOPR protocols.

3 See NYISO's Market Administration and Control Area Services Tariff section 23.4.5.7.9.

4 See Commission's 6 June, 2019 order directing the IMM to make a deficiency filing in the matter of *Results of Thirteenth Forward Capacity Auction*, Docket No. ER19-1166-000.

ISO-NE's version of the MOPR always sets the offer floor at the new resource's actual entry cost, even though it may be much higher than net CONE (currently near $8 per kw-month). This may prevent state-sponsored resources that could satisfy a capacity need from clearing in the FCA and prompt the ISO to clear a conventional resource that is not needed (given the entry of the sponsored resource). This raises additional concerns under the ISO's recently approved Competitive Auctions with Subsidized Policy Resources ("CASPR") provisions because clearing unneeded conventional resources will compel the sponsored resources to pay lower-cost existing resources to retire.

Addressing this issue is straightforward. We recommend that ISO-NE cap the minimum offer price at net CONE. This will prevent artificial suppression of capacity prices below net CONE, but would ameliorate the concerns described above. It would allow sponsored resources to enter at an offer equal to net CONE and displace new conventional resources offered at higher prices. To the extent that some sponsored resources clear in the FCA at or above net CONE, fewer lower-cost existing resources would be prompted to retire and fewer unneeded conventional new resources would enter, both of which would increase efficiency and lower costs for the regions' consumers.

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:[5]

- Limited competition can enable a single supplier to unilaterally raise the capacity clearing price by a substantial amount.
- Publishing information on qualified capacity and the Descending Clock Auction format help suppliers recognize when they can benefit by raising capacity prices.

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. Accordingly, we recommend the ISO transition from the DCA to a sealed-bid auction.

5 See Section V.A of our report on *2014 Assessment of the ISO New England Electricity Markets*, Section IV.A of *2015 Assessment of the ISO New England Electricity Markets*, and Section IV.A of *2017 Assessment of the ISO New England Electricity Markets*.

Causes and Allocation of NCPC Charges

Although the overall size of NCPC payments are small relative to the overall New England wholesale market, they raise a number of important concerns:

- They usually indicate that the markets do not fully reflect the needs of the system. Ultimately, this undermines the price 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.
- NCPC payments can also distort suppliers' incentives. Thus, we evaluate the causes of NCPC payments to identify market improvements that would limit such distortions.
- NCPC payments tend to shift investment incentives away from flexible resources that will be increasingly valuable with the growth in intermittent renewable generation.

Our evaluation in this report shows that even with the improvements made in recent years, ISO-NE's uplift charges exceed the levels generated by most other RTOs. Given the concerns that NCPC payments raise, we evaluate the causes of NCPC payments in order to identify potential market improvements.

Day-Ahead NCPC Charges

In our assessment of day-ahead NCPC charges, we found that in 2018, 47 percent was attributable to commitments for local second contingency protection, while 30 percent was attributable to commitments for the system-level 10-minute spinning reserve requirement. Although these requirements are reflected in the real-time market, there is no day-ahead market for operating reserves. Thus, the costs of committing generation to satisfy these requirements are not reflected efficiently in day-ahead prices. This process resulted in:

- Excess commitments by the day-ahead market model for local second contingency protection in Boston, 60 percent of which would not have been needed under a co-optimized energy and reserve market.[6]
- Depressed clearing prices for energy and 10-minute spinning reserves providers. We estimate that additional generation was committed to satisfy the 10-minute spinning reserve requirement in nearly 4,000 hours in 2018, although this was not reflected in energy prices or spinning reserve prices.

In addition, we continue to find that NCPC costs are inflated when the ISO is 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.

6 Note, this includes LSCPR units that were committed by a constraint in the day-ahead commitment model, while the majority of LSCPR units in Boston were determined before the day-ahead market.

We make three recommendations to improve the pricing of energy and operating reserves.

- We recommend that the ISO co-optimize the scheduling and pricing of operating reserves with energy in the day-ahead market (i.e., determine the lowest cost set of offers that simultaneously satisfies energy demand and operating reserve requirements).
- A day-ahead reserve market would also facilitate our recommendation to eliminate of the Forward Reserve Market, which has resulted in inefficient economic signals and market costs.
- We recommend the ISO expand its authority to commit combined-cycle units in a single-turbine configuration when that will satisfy its reliability need.

ISO-NE has started several initiatives to address energy security concerns, including co-optimizing procurement of energy and operating reserve in the day-ahead market. We support this effort and expect it will address the issues we identified and discussed in this report.

Real-Time NCPC Charges and Allocations

In assessing the real-time NCPC charges in 2018, we found that 9 percent were for local reliability and 14 percent were for system level capacity requirements, while the vast majority were associated with inconsistencies between the output of economically scheduled generators and clearing prices in the real-time market.

Similar to our prior findings, we found that real-time deviations contribute to just 14 percent of the real-time NCPC in 2018, but they are allocated 40 percent of the NCPC charges. Hence, we continue to find that ISO-NE over-allocates real-time NCPC charges to virtual transactions and other real-time deviations. This has substantially reduced virtual trading activity and the overall liquidity of the day-ahead market. In 2018, the gross volume of cleared virtuals (including both virtual load and virtual supply) averaged roughly 7 percent of load in the ISO-NE market compared to nearly 20 percent in the NYISO and MISO markets.

The ISO is currently considering a market design improvement, a Multi-day Ahead Market, to address energy security concerns. Virtual trading will be playing a very important role in aligning prices in the multi-day ahead market with the prices in the real-time market. Therefore, we recommend that the ISO modify the allocation of Economic NCPC charges to be more consistent with a “cost causation” principle, which would largely involve not allocating NCPC costs to virtual load and other real-time deviations that do not cause it.

Table of Recommendations

We make the following recommendations based on our assessments of the ISO-NE's market performance. A number of these recommendations have been made previously and are now reflected in the ISO's Wholesale Market Plan.

Recommendation	Wholesale Mkt Plan	High Benefit[7]	Feasible in ST[8]
Reliability Commitments and NCPC Allocation			
1. Modify allocation of "Economic" NCPC charges to make it consistent with a "cost causation" principle.	✓		✓
2. Utilize the lowest-cost fuel and/or configuration for multi-unit generators when committed for local reliability.			✓
Reserve Markets			
3. Introduce day-ahead operating reserve markets that are co-optimized with the day-ahead energy market.	✓	✓	
4. Eliminate the forward reserve market.			✓
External Transactions			
5. Pursue improvements to the price forecasting that is the basis for Coordinated Transaction Scheduling with NYISO.		✓	✓
Capacity Market			
6. Replace the descending clock auction with a sealed-bid auction to improve competition in the FCA.			✓
7. Modify the PPR to rise with the reserve shortage level, and not implement the remaining planned increase in the payment rate.			
8. Consider modifying the capacity compensation of energy limited resources to be consistent with the reliability value.			
9. Improve the MOPR by: a) eliminating performance payment eligibility for units subject to the MOPR, b) capping the Minimum Offer Price at net CONE, and c) exempting competitive private investment from the MOPR.			✓

7 Recommendation will likely produce considerable efficiency benefits.

8 Complexity and required software modifications are likely limited.

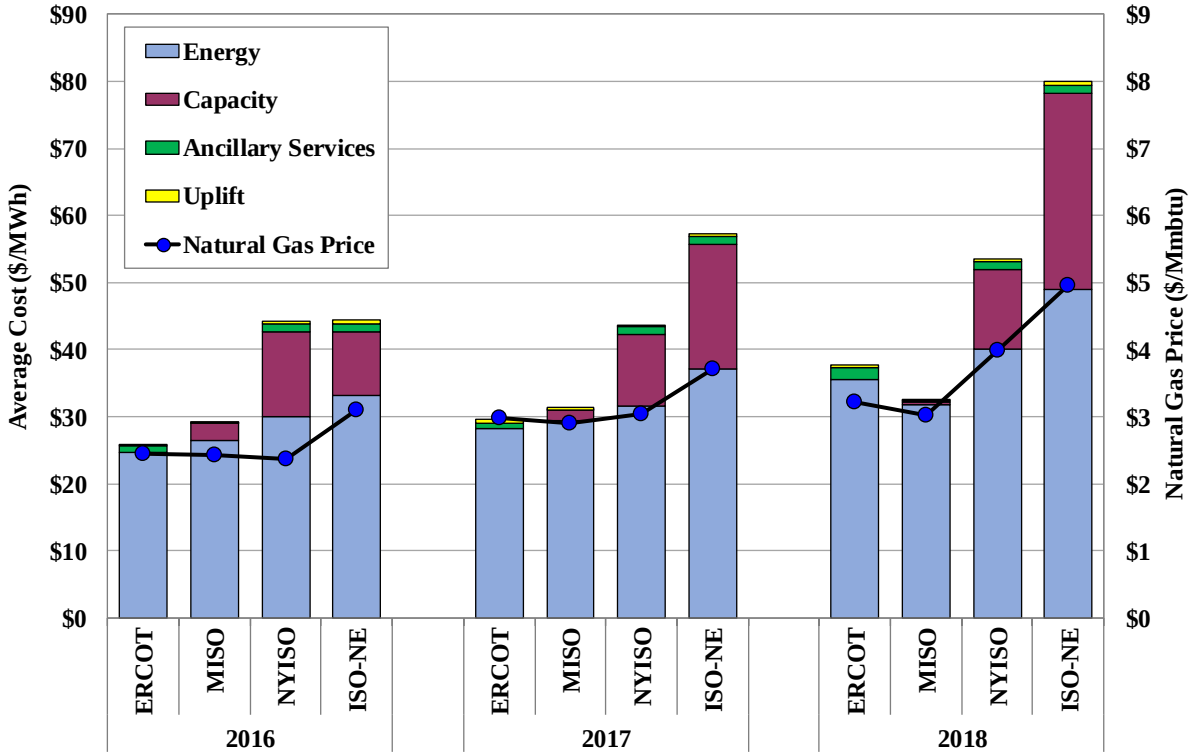
I. Comparing Key ISO-NE Market Metrics to Other RTOs

The 2018 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 2018. Rather than duplicating this discussion, we attempt to place the key market outcomes into perspective in this section by comparing them to comparable outcomes and metrics in other RTO markets.

A. Market Prices and Costs

While the RTOs in the US have migrated to relatively similar market designs, including Locational Marginal Pricing (LMP) energy markets, operating reserves and regulation markets, and capacity markets, the details related to the market rules can vary substantially. Additionally, 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
2016 - 2018



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 real-time

uplift costs per MWh of real-time load. We also show the average natural gas price because it is a principal driver of generators' marginal costs and energy prices in most markets.

This figure shows some clear sustained differences in prices and costs between these markets. ISO-NE has generally exhibited the highest energy prices and uplift costs of these markets. The relatively high energy costs are in New England are primarily attributable to the higher natural gas prices at the pipeline delivery locations serving New England's generators. However, the natural gas price premium is larger than the energy price premium in New England because average system-wide energy prices in all other markets are inflated by transmission congestion. Although we do not show the most congested locations in neighboring markets, such as New York City, these locations exhibit all-in 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 lead to lower system-wide average energy prices. We discuss congestion levels and trends in more detail in the next subsection.

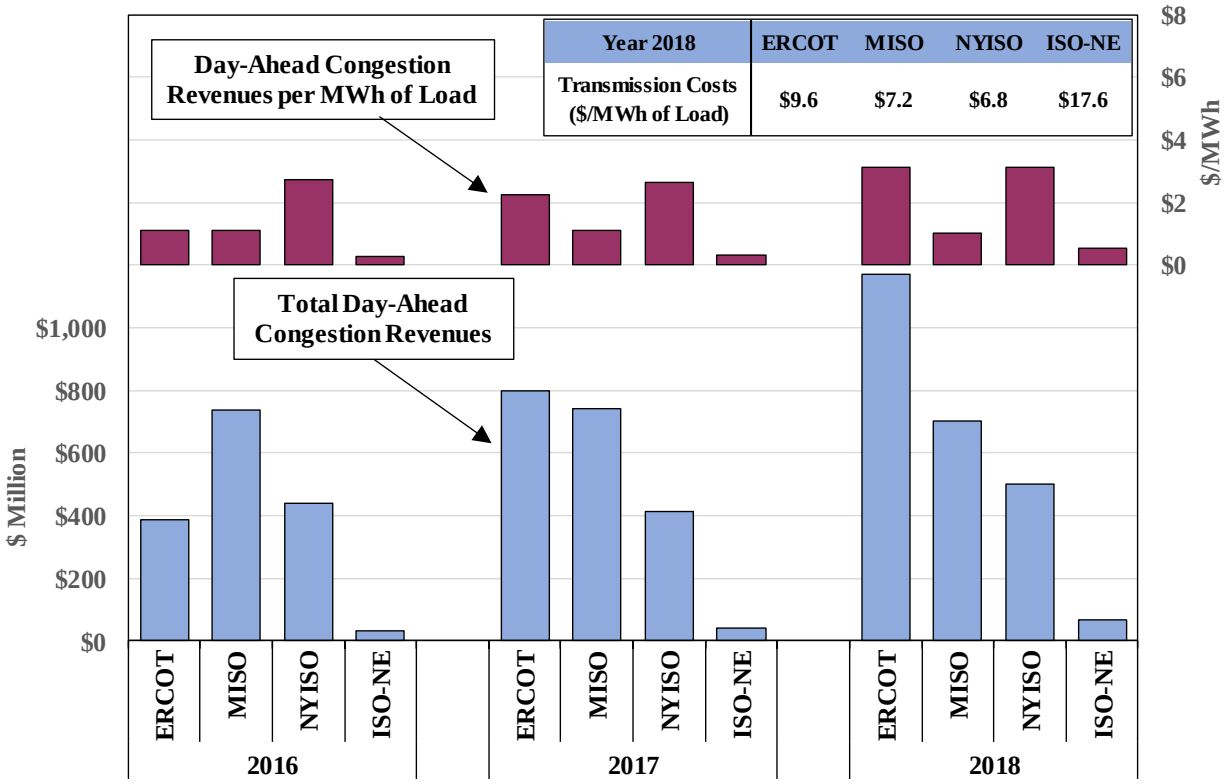
The figure also that the capacity component of the all-in prices is substantially higher than the other RTO's shown. The capacity costs are NYISO are lower primarily because its surplus in the 2018 planning year is higher than the surplus in New England. The low capacity costs in the other two RTOs is attributable to the market design. ERCOT operates an "energy-only" with no capacity market, while MISO operates a capacity auction with a vertical demand curve that is not design to reveal the true value of capacity. Although not optimal, MISO has been content with this market design because additional revenues are provided through retail rates to regulated entities that play a key role in maintaining resource adequacy in MISO.

The other result shown in the figure, although it is difficult to discern, is that the average uplift costs per MWh is higher in ISO-NE than any of the other markets shown. Although this amount appears small, it is important because it is difficult to hedge. Owning or contracting for generation will hedge load-serving entities against volatile costs of procuring energy and ancillary services, but uplift costs are an additional cost that is not typically hedged by supply procurements. The categories of uplift and a discussion of the reasons for the higher uplift levels incurred in New England are discussed in Section III in this report.

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. The following figure 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: Day-Ahead Transmission Revenues
2016 - 2018



This figure shows that ISO-NE experiences far less congestion than any of these other RTOs. On a per MWh basis, congestion levels in the other RTOs are five to ten times larger than the congestion levels 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 to transmission rates that are more than double the average rates in the other RTO areas at nearly $18 per MWh. The transmission rates in other RTO areas are much lower than 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 resource in west Texas and the load centers in eastern Texas.

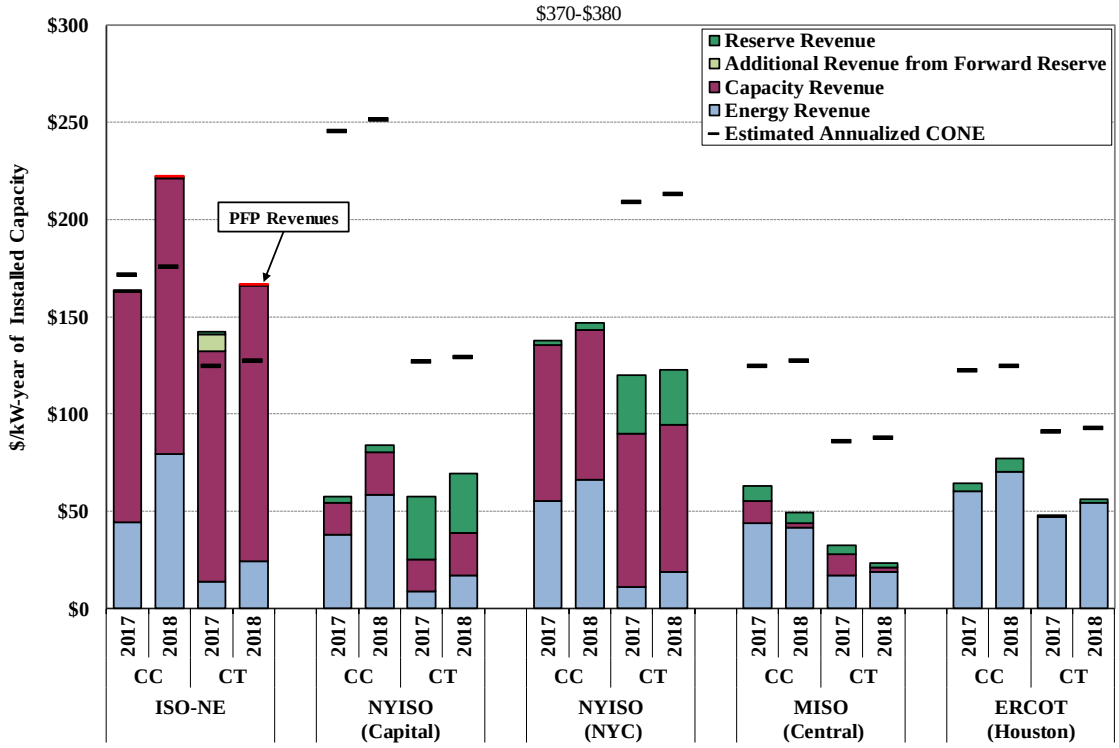
Going forward, economic transmission investment should occur when the marginal benefit of reducing congestion is greater than the marginal cost of the transmission investment. Given that average congestion in New England has been less than $0.40 per MWh over the past three years, it is unlikely that additional transmission investment will be economic in the near term.

C. Long-Term Economic Signals

While price signals play an essential role in coordinated commitment and dispatch of units in the short term, they also provide long-term economic signals that govern investment and retirement decisions for generators and transmission. This section compares the long-term economic signals in ISO-New England to other markets by measuring the net revenue a new generating unit would have earned over the past two years.

Net revenue is the revenue a new unit would earn above its variable production costs if it ran when it was economic to run. A well-designed market should produce net revenue sufficient to support new investment when existing resources are not adequate to meet the system's needs. Figure 3 show estimated net revenues for a new combustion turbine (CT) and combined-cycle (CC) generator for the prior two years in New England and other RTO markets. For comparison, the figures also show the annual net revenue that would be needed for these new investments to be profitable (i.e., the "Cost of New Entry" or CONE).

Figure 3: Net Revenues Produced in ISO-NE and Other RTO Markets
2017 - 2018



This figure shows that Net Revenues provided by the ISO-NE markets increased substantially in 2018. As in most of the other RTO markets, the energy net revenues increased as natural gas prices increased and both types of new resources received higher inframarginal energy revenues. In addition to the energy revenues, the capacity net revenues increased substantially as capacity prices have increased. This increase in capacity revenues contributed to net revenues in New

England in 2018 that exceeded the entry costs for both types of new resources. However, several new resources have entered the market since FCA 10 (i.e. 2019/20) which resulted in a substantial drop in capacity prices. Hence, the total revenues of both types of hypothetical units may be lower than their in respective CONEs for future years.

This outcome in 2018 is unique to New England as none of the other RTO markets produced net revenues that were sufficient to cover the costs of investing in new combustion turbines or combined cycle resources. In New York, this outcome is attributable to the prevailing capacity surpluses. In MISO, this result is due to a poorly designed capacity market that prevents it from delivering efficient revenues, while ERCOT lacks a capacity market and did not experience the shortages in 2017 or 2018 that would be needed to incent new investment. In some areas such as New York and ERCOT, new entry by merchant generators has occurred despite relatively low net revenues. This can occur when a generation site benefits from some special competitive advantage, such as close proximity to a low-priced natural gas pipeline or when investors are particularly optimistic about future market conditions.

Resources in New England also benefit from a number of other revenue streams including PFP, Forward Reserve Markets, and compensation for enhancing reliability during winter months (e.g. Winter Reliability Program and the Interim Compensation for FCA 14 and FCA 15). Although, the total of such revenues was relatively small in 2017 and 2018, they could comprise an increasing share of revenues in future years as the ISO increases the PPR and designs additional products for enhancing energy security during winter months.

D. Coordinated Transaction Scheduling

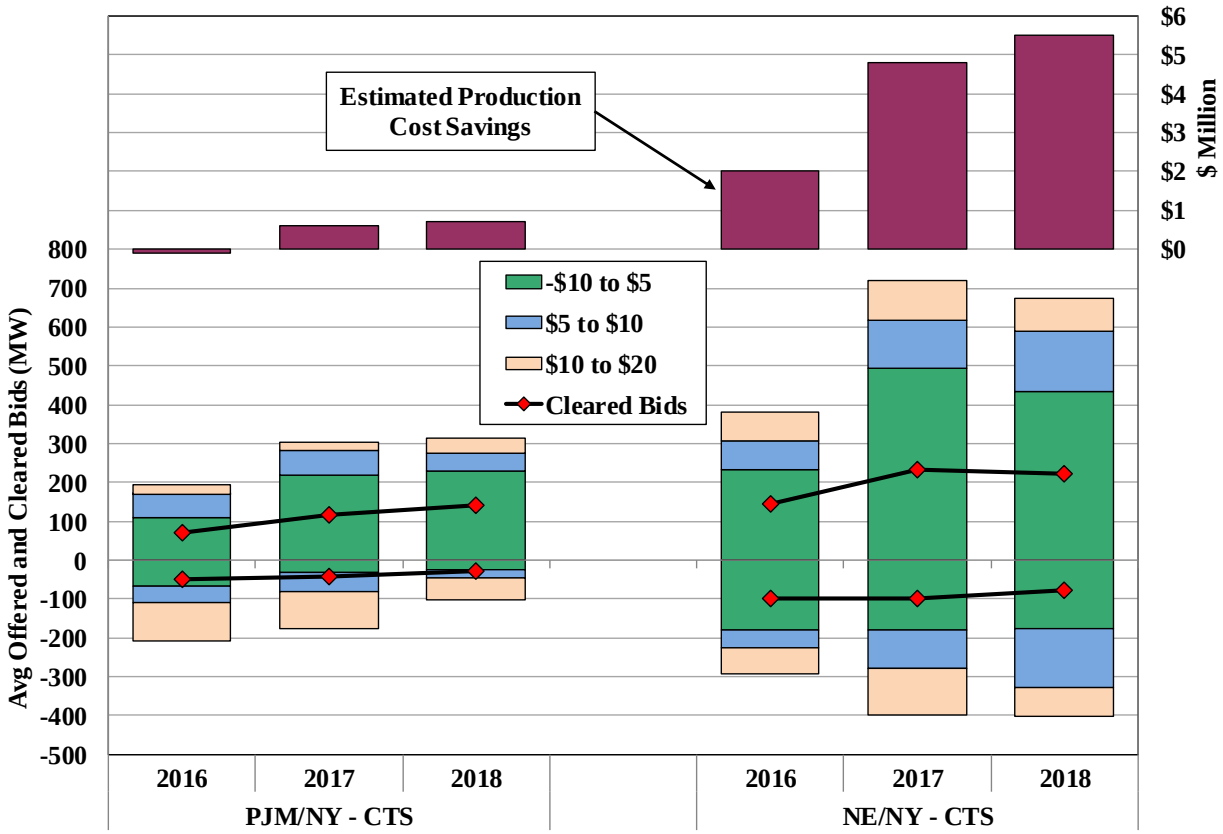
Coordinated Transaction Scheduling ("CTS") is a market process whereby two neighboring RTOs exchange real-time market information to schedule external transactions more efficiently. CTS is very important because it allows the large interface between markets to be more fully utilized, which lowers costs 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 4 evaluates the overall efficiency of the CTS scheduling process between ISO-NE and the NYISO, compared to the CTS process between PJM and the NYISO. The bottom portion of the figure shows annual average quantities of price-sensitivity of CTS bids for three price ranges and schedules during peak hours (i.e., HB 7 to 22) from 2016 to 2018. Positive numbers indicate export bids from New England or PJM to New York and negative numbers represent import

offers from New York to New England or PJM. The upper portion of the figure shows the market efficiency gains (and losses) from CTS, which is measured by production cost savings.[9]

The average amount of price-sensitive bids was significantly larger at the NE/NY interface than at the PJM/NY interface. In 2018, the amount of bids offered between $-10 and $10 per MWh averaged over 900 MW (including both import offers and export bids) at the NE/NY interface, more than double the amount at the PJM/NY interface. Likewise, the cleared bids in the same price range at the NE/NY interface nearly doubled the amount cleared at the PJM/NY interface. This has allowed more flow adjustments (in terms of both frequency and magnitude) at the NE/NY interface, contributing to much higher production cost savings.

Figure 4: CTS Scheduling and Efficiency
2016 - 2018



The difference between the two CTS processes is largely attributable to the large fees that are imposed at the PJM/NY interface while there are no substantial transmission charges or uplift

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.

charges on transactions at the NE/NY interface. Typically, the NYISO charges physical exports to PJM at a rate ranging from $4 to $8 per MWh, while PJM charges physical imports and exports a transmission rate and uplift allocation that averages less than $3 per MWh. These charges are a significant economic barrier to achieving the potential benefits from the CTS process, since large and uncertain charges deter participants from submitting efficient CTS offers. This is particularly evident from the fact that almost no CTS bids were offered at less than $5 per MWh from NYISO to PJM. This demonstrates that imposing substantial charges on low-margin trading activity has a dramatic effect on the liquility of the CTS process.

The estimated production cost savings from the CTS process between New England and New York increased from $2.0 million in 2016 to $5.5 million in 2018, indicating that the overall performance of this CTS process has improved notably over the past three years. In addition to increased price-sensitive bidding volumes over time, this improvement was also attributable to better price forecasting.

- ISO-NE forecast errors fell from 33 percent in 2016 to 20 percent in 2018, while NYISO forecast errors fell from 29 percent in 2016 to 24 percent in 2018.
- In contrast, price forecasting by PJM was the worst among the three ISOs in 2018, largely responsible for worse CTS performance at the PJM/NY interface.
- ISO-NE's price forecasting is more accurate partly because it forecasts a supply curve (with 7 points representing 7 different interchange levels at the interface), while PJM only forecasts a single price point at one assumed interchange level.

Despite the better performance at the NE/NY interface, the volume of price-sensitive CTS bids was still modest compared to the transfer capability of the interface. This is likely attributable to: (a) interchange ramp limitations, which prevent the interchange from changing by more than 300 MW at each quarter hour and (b) the risk that CTS transactions may be scheduled but be unprofitable because of forecast errors in the scheduling process. Thus, if the ISOs can improve the price forecasts that underlie the CTS prices, it should further improve both the quantity and the price-sensitivity of the CTS bids, and ultimately allow the process to achieve larger savings. Our evaluation of the price forecasting errors at the NE/NY interface indicated that:[10]

- Errors in load forecasting and wind forecasting were the largest contributor (23 percent).
- Differences in timing and ramp profiles between forecasting model and dispatch model were the second largest contributor (22 percent).
- Forced outages and poor dispatch performance by generators were the third largest contributor (15 percent).
- Other factors also made significant contributions collectively, but these had relatively small impacts individually.

[10] See Section VI.C in our *2017 Assessment of the ISO New England Electricity Markets*.

Therefore, there is ample opportunity to improve the performance of the CTS process at the NE/NY interface. Nonetheless, it is important to note that the CTS process with NYISO is by far the best performing CTS that has been implemented to date (CTS process have been implemented between PJM and both NYISO and MISO). The primary reason the other CTS processes have performed poorly is that the CTS are allocated substantially costs and transmission charges. We applaud ISO-NE and NYISO for agreeing not to charge such fees to their CTS transactions. We will continue monitor the performance of CTS and evaluate factors that contribute to particularly large forecast errors.

II. Competitive Assessment of the Energy Market

This section evaluates the competitive performance of the ISO-NE energy market in 2018. 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.[11] 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 economically or physically withholding generating resources. 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 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.

[11] 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;[12] 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.

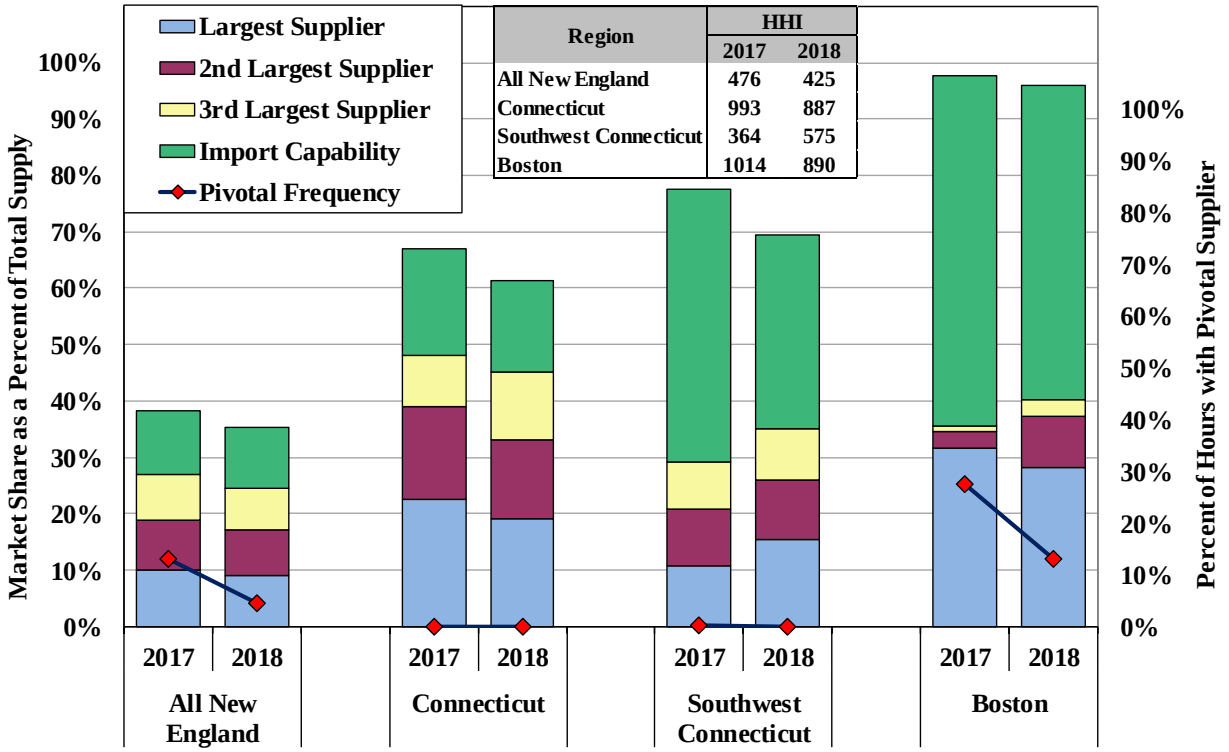
The Pivotal Supplier Test is a more reliable means to evaluate the competitiveness of energy markets because it recognizes the importance of both supply and demand. Whether a supplier is pivotal depends on the size of the supplier as well as the amount of excess supply (above the demand) held by other 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

12 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 raise clearing prices. For the supplier to have the incentive to raise prices, it must have other supply that would benefit from higher prices.

Figure 5 shows the three structural market power indicators for each of the four regions in 2017 and 2018. First, the figure shows the market shares of the largest three suppliers and the import capability in each region in the stacked bars.[13,14] 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
2017 – 2018



Region	HHI 2017	HHI 2018
All New England	476	425
Connecticut	993	887
Southwest Connecticut	364	575
Boston	1014	890

13 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.

14 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 Base Interface Limit (or Capacity Import Capability) is used for external interfaces, and the N-1-1 Import Limits are used for the reserve zone.

Figure 5 indicates that market concentration of internal generation increased in Southwest Connecticut from 2017 to 2018 but fell in other three regions. This was driven primarily by new market entry and ownership changes for the largest suppliers. Two new combined cycle power plants, the CPV Towantic plant and the Footprint plant, came into full service in mid-2018, adding roughly 800 MW of generating capacity in Southwest Connecticut and 700 MW in Boston. Both facilities were managed by the same lead market participant, who became one of the three largest suppliers in 2018. On the other hand, the portfolio sizes of the three largest suppliers in 2017 all decreased (by varying amounts) and two of them were no longer among the top three suppliers in 2018. As a result, the collective market share of the three largest suppliers in all New England fell modestly from roughly 27 percent in 2017 to less than 25 percent in 2018. In Boston, the largest supplier's share also decreased.

The figure also shows variations in the number of suppliers with large market shares across the four areas. In 2018, Boston had one supplier with a large market share of 28 percent, while all New England has three suppliers with market shares of less than 10 percent each. Import capability accounts for a significant share of total supply in each region (ranging from 11 percent in all New England to 56 percent in Boston), so 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 2018, which indicates that:

- In Southwest Connecticut and Connecticut, there were very few hours (< 0.5 percent) when a supplier was pivotal in 2018.
- In Boston, one supplier owned nearly 65 percent of the internal capacity, but was pivotal in just 13 percent of hours in 2018. 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 5 percent of hours in 2018.[15]

The pivotal frequency fell in Boston because of the new entry of the Footprint power plant, which led to less frequent commitments of the Mystic facilities in the portfolio of the largest supplier in Boston. In addition, the Greater Boston Reliability Project made significant progress in the last two years. Planned transmission outages, which were needed for these transmission upgrades, were less frequent in the Boston area during 2018. Completed transmission upgrades

[15] The pivotal supplier results are conservative for "All New England" compared to those evaluated by the IMM (see their 2018 SOM report, Section 3.7.3) 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.

also helped increase import capability into the area.[16] As a result, the supplier in Boston was pivotal less frequently in spite of higher load levels in 2018.

The pivotal frequency decreased in all New England as well. This resulted largely from new entry and ownership changes for the largest suppliers mentioned above. Other key contributing factors included:

- The availability of pumped-storage hydro generation increased in 2018 relative to 2017 because of fewer generation outages;
- Net imports from New York rose noticeably; and
- Price-responsive demand resources started to participate in the energy market in June 2018, satisfying a significant portion of reserve requirements.

Taken together, these led the supplier to be pivotal much less frequently in 2018.

In spite of the reduction in pivotal frequency, 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.[17] 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.
- Physical withholding: we analyze short-term deratings and outages because they are most likely to reflect attempts to physically withhold resources because 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.

16 The N-1-1 import capability into Boston is expected to increase by more than 400 MW upon the completion of the Greater Boston Reliability Project in mid-2019.

17 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.

Competitive Assessment

The following analysis shows the output gap results and physical deratings relative to load and participant characteristics. The objective is to determine whether the output gap and/or 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 physical deratings vary in a manner consistent with attempts to exercise market power.

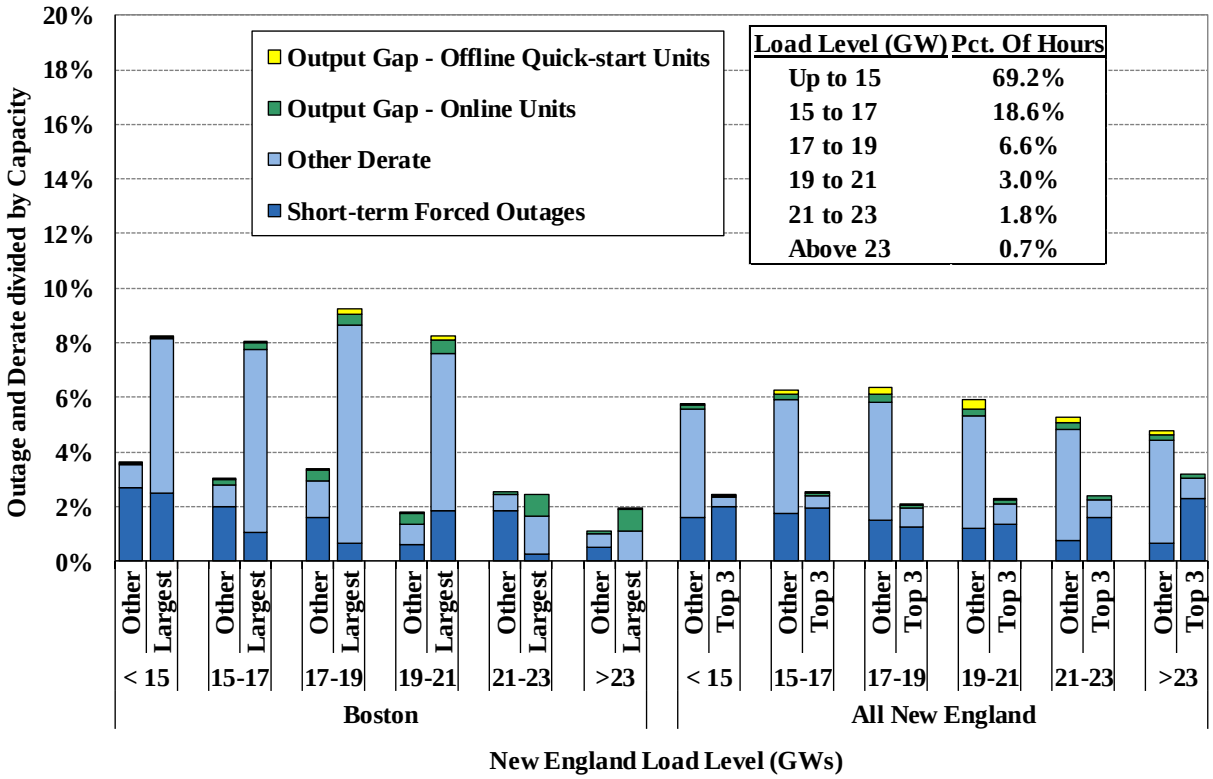
Because the pivotal supplier analysis raises competitive concerns in Boston and all New England, Figure 6 shows the output gap and physical deratings by load level in these two regions. The output gap is calculated separately for:

- 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 physical withholding analyses focus on:

- 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. The "Other Derates" can be the result of ambient temperature changes or other legitimate factors.

Figure 6: Average Output Gap and Deratings by Load Level and Type of Supplier
Boston and All New England, 2018



The figure above shows the supplier's output gap and physical deratings as a percentage of its portfolio size in Boston and all New England by load level. In Boston, we compare these statistics for the largest supplier, who owned roughly 65 percent of internal generating capacity in 2018, to all other suppliers in the area. In all New England, we compare the three largest suppliers, who collectively owned roughly 25 percent of internal generating capacity in 2018, to all other suppliers.

In Boston, as was seen in the prior years, the amount of "Other Derate" in the largest supplier's portfolio was notably higher during low load periods. This was because its combined-cycle capacity was frequently offered and operated in reduced configuration during these periods (e.g., overnight hours). This is generally efficient and does not raise significant competitive concerns..

Excluding the contributions of the "Other Derates" in Boston for the reasons described above, Figure 6 shows that the overall output gap and deratings were not significant as a share of the total capacity in both Boston and all New England. The total amount of output gap and 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 and other smaller suppliers in each region exhibited comparable levels of overall output gap and deratings, particularly at higher load levels when prices are most sensitive to potential withholding. 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 2018 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: [18]

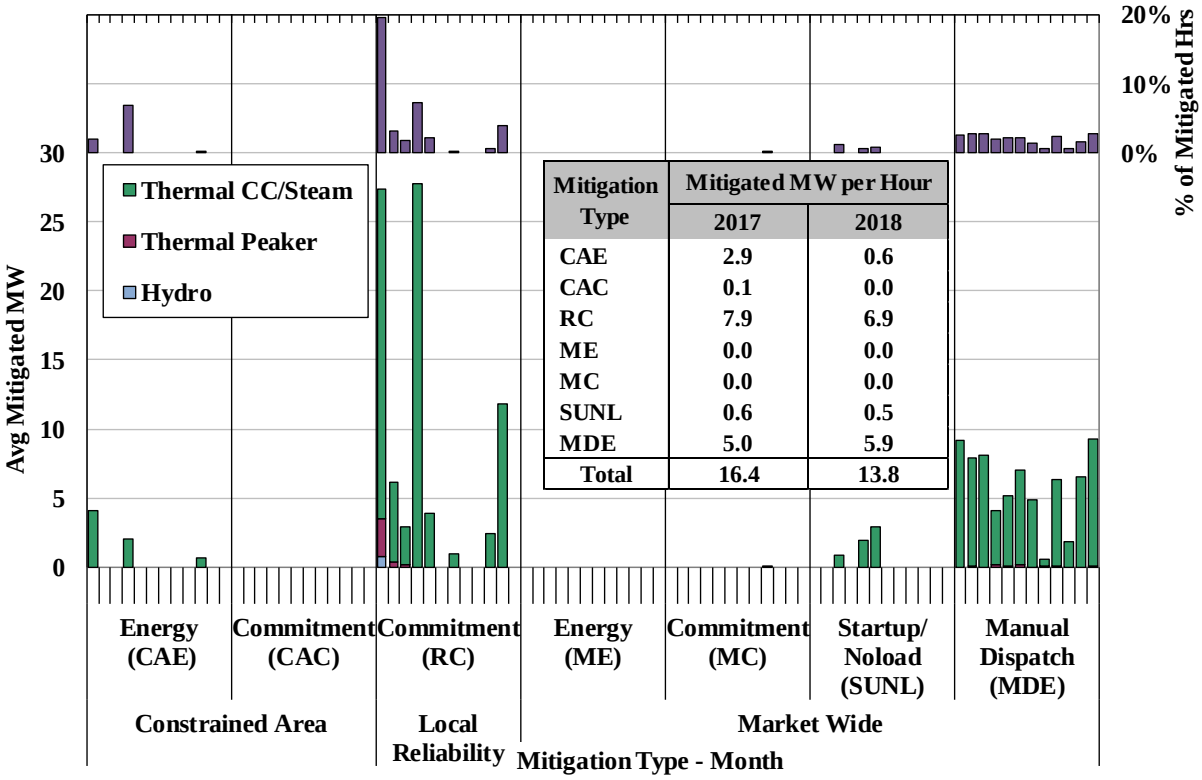
[18] See Market Rule 1, Appendix A, Section III.A.5 for details on these tests and thresholds.

- Market-Wide Energy Mitigation ("ME") – ME mitigation is applied to any resource that is in the portfolio of a pivotal Market Participant.
- Market-Wide Commitment Mitigation ("MC") – MC mitigation is applied to any resource whose Market Participant is determined to be 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 is only applied to 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.

Figure 7 examines the frequency and quantity of mitigation in the real-time energy market. 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 2017 and 2018.

Figure 7: Frequency of Real-Time Mitigation by Mitigation Type and Unit Type
By Month, 2018



Mitigation Type	Mitigated MW per Hour	
	2017	2018
CAE	2.9	0.6
CAC	0.1	0.0
RC	7.9	6.9
ME	0.0	0.0
MC	0.0	0.0
SUNL	0.6	0.5
MDE	5.0	5.9
Total	16.4	13.8

Roughly 92 percent of all mitigation was for either local reliability commitment or manual dispatch energy. Both typically occurred more frequently during the shoulder months because of higher local reliability needs that were often caused by planned transmission outages. 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.

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. Likewise, generators are sometimes not required to burn the lowest-cost fuel – e.g., a substantial amount of NCPC was paid in 2018 to a unit that usually burned oil when natural gas was much less expensive. We discuss the two issues in more detail in Section III and continue to recommend that the ISO consider tariff changes that would expand its authority to address these issues.

The amount of non-local-reliability mitigation has been low in recent years because the hourly offer market enhancement that was implemented in December 2014 has allowed suppliers to more accurately reflect their fuel costs (or opportunity costs) on an hourly basis and in a more timely manner. This has improved not only the competitiveness of supply offers but also the accuracy of the mitigation, particularly for:

- Energy limited hydro resources, whose 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, which become economic when gas prices rise above oil prices, but 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 must be determined by 2 pm on the prior day.

To supplement this improvement in offer flexibility, reference level adjustments should be made as necessary to account for the opportunity costs associated with these types of energy limitations. 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.

We examined market outcomes during the cold spell in the 2017/18 winter to evaluate whether the lack of appropriate opportunity costs in the reference prices had significantly affected efficient market outcomes. We found that:

- There were very few resources that appeared to be limited by the market power mitigation thresholds because of low reference levels. We reviewed offers from the resources with tight oil inventories and found only one resource that appeared to offer just below one of the thresholds (which was also postured by the ISO on several occasions during the cold spell); and
- No resources were mitigated when economically committed or dispatched during the cold spell.

These observations suggest that while the reference levels may have been under-stated, there was a limited impact on market outcomes. Nonetheless, ISO-NE has recognized the issue and developed 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 opportunity cost is calculated in a way consistent with profit-maximizing with limited fuel supply over a rolling seven-day period. This has been effective since December 2018, but the 2018/19 winter was relatively mild. Consequently, the use of oil was substantially lower in the 2018/19 winter and there was sufficient oil inventory throughout the winter. Therefore, the effectiveness of the

opportunity cost estimator has not yet been challenged by tight market conditions. Nonetheless, this reference calculation enhancement should help address fuel security issues that ISO-NE faces by allowing generators to conserve fuel more effectively with their offers in the future.

E. Competitive Performance Conclusions

The pivotal supplier analysis suggests that structural market power concerns diminished noticeably in Boston and in all New England in 2018, driven largely by the new market entry of roughly 1.5 GW of combined cycle generating capacity, ownership changes for the largest suppliers, and transmission upgrades in Boston. 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 2018.

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. 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.

The ISO has implemented a procedure to calculate an opportunity cost for oil-fired and dual-fuel generators with limited fuel inventories to be incorporated in their reference prices. This enhancement should lead to more efficient scheduling of energy-limited resources. However, its effectiveness was not truly tested because of relatively mild winter conditions. We will continue monitor this and evaluate how the opportunity cost estimator performs particularly under prolonged severe winter weather conditions.

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. Hence, we recommend the ISO to consider changes that would address this concern.

III. CAUSES AND ALLOCATION OF NCPC CHARGES

When resources are scheduled at clearing prices that produce market revenues that are less than their full as-bid costs, ISO-NE provides an NCPC payment to cover the revenue shortfall. Although the overall size of NCPC payments are small relative to the overall New England wholesale market, NCPC payments are important because they usually occur when the market requirements are not fully aligned with the system's reliability needs or prices are otherwise not fully efficient. Additionally, sustained levels of NCPC can distort the market participants' incentives. Thus, we evaluate the causes of NCPC payments to identify potential inefficiencies.

Like other wholesale electricity markets, the ISO-NE uses a uniform price auction to coordinate the scheduling of resources. The profit-maximizing offer of a competitive supplier in a uniform price auction is its short-run marginal cost, which it can determine without having to make predictions of market clearing prices. In some cases, however, NCPC payments provide incentives for suppliers to raise their offer prices above short-run marginal cost to increase their payments.

Most NCPC payments occur when an operating requirement is not fully reflected in the market's requirements and must therefore be satisfied by scheduling a resource outside of the market. The cost of this action 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.

Additionally, intermittent renewable generation will likely become more prevalent over the coming decade, which will increase the value of flexible resources. NCPC payments do not provide efficient incentives because they generally reward resources for being high-cost and inflexible. Hence, NCPC payments tend to shift investment incentives away from flexible resources at locations that would bolster transmission security and reliability.

This section evaluates the causes of NCPC charges in 2018 and discusses implications for market efficiency, divided into subsections that address the following topics:

- Comparison of uplift charges and allocations in ISO-NE versus other markets;
- Primary drivers of day-ahead NCPC charges;
- Local second contingency protection requirements that lead to day-ahead NCPC charges;
- System-level operating reserve requirements that lead to day-ahead NCPC charges;
- Discussion of significant drivers of real-time NCPC charges; and
- Summary of conclusions and recommendations.

A. Cross-Market Comparison of Uplift Charges and Cost Allocation

Before discussing the causes and implications of various classes of NCPC costs (generally referred to as "uplift" costs industry-wide), it is useful to place ISO-NE's NCPC charges in context. Table 1 shows its total day-ahead and real-time NCPC charges over the past three years, and the comparable 2018 uplift charges for the NYISO and the 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
		2016	2017	2018	2018	2018
Real-Time Uplift						
Total	**Local Reliability ($M)**	$1	$1	$4	$23	$3
	Market-Wide ($M)	$27	$23	$40	$19	$78
Per MWh of Load	**Local Reliability ($/MWh)**	$0.01	$0.01	$0.04	$0.14	$0.004
	Market-Wide ($/MWh)	$0.22	$0.19	$0.32	$0.12	$0.11
Day-Ahead Uplift						
Total	**Local Reliability ($M)**	$31	$15	$14	$31	$22
	Market-Wide ($M)	$13	$13	$12	$4	$17
Per MWh of Load	**Local Reliability ($/MWh)**	$0.25	$0.12	$0.11	$0.19	$0.03
	Market-Wide ($/MWh)	$0.10	$0.11	$0.10	$0.03	$0.03
Total Uplift						
Total	**Local Reliability ($M)**	$33	$16	$18	$54	$25
	Market-Wide ($M)	$40	$36	$52	$23	$95
Per MWh of Load	**Local Reliability ($/MWh)**	**$0.26**	**$0.13**	**$0.15**	**$0.33**	**$0.04**
	Market-Wide ($/MWh)	**$0.32**	**$0.29**	**$0.42**	**$0.14**	**$0.14**
	All Uplift ($/MWh)	**$0.58**	**$0.42**	**$0.57**	**$0.48**	**$0.17**

The table shows that ISO-NE incurs more uplift costs, adjusted for its size, than the other two markets. Most of these higher uplift costs are associated with ISO-NE's market-wide needs. In 2018, ISO-NE's market-wide NCPC uplift was roughly triple the costs per MWh incurred by NYISO or MISO in 2018. Most of the increase was attributable to the cold spell in the first week of January, which accounted for nearly 25 percent of all NCPC uplift in 2018. Excluding this one-week period, market-wide NCPC uplift would have been comparable to the costs in 2017.

Even excluding the effects of the cold spell in early 2018, however, the market-wide uplift costs are significantly higher than comparable costs in other RTOs. The higher market-wide costs are partly because ISO-NE's fuel costs tend to be higher than the other RTO's, which generally leads to higher required make-whole payments. However, higher fuel costs are only one of the important drivers. We discuss the other drivers of these uplifts in subsections B and E.

Table 1 also shows that local reliability NCPC uplift fell notably in the last two years. This was driven primarily by reduced supplemental commitments in the Boston area because of:

- The transmission upgrades (i.e., the Greater Boston Reliability Project), which have increased the import capability into the Boston load pocket; and
- The new entry of the 700 MW Footprint combined-cycle plant.

These factors have greatly reduced the ISO's reliance on the Mystic generating units which were previously committed frequently to maintain reliability in the Boston area. Uplift for local reliability is smaller than in the NYISO, where generation must be committed for local second contingency protection in New York City. However, local reliability uplift is smaller in the MISO where few areas require commitment for local second contingency protection.

In addition to the differences in the magnitude of the uplift costs, the allocation of the uplift costs also vary substantially among the RTOs. ISO-NE allocated approximately half real-time NCPC charges to real-time deviations, including virtual transactions. This has resulted in higher costs incurred by virtual transactions in New England than in other RTO markets.

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. However, we have observed relatively low levels of virtual trading in ISO-NE compared to other markets we monitor, which we attribute primarily to the allocation of relatively large NCPC charges (per MWh) to virtual transactions, virtual load in particular.

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 gross 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
		MW as a % of Load	Avg Profit	MW as a % of Load	Avg Profit	Charge Rate
ISO-NE	2016	1.3%	$1.70	2.0%	$1.94	$1.25
	2017	2.2%	$1.98	3.6%	$2.71	$0.81
	2018	2.7%	$1.10	4.5%	$2.69	$0.94
NYISO	2018	5.7%	$1.54	12.3%	-$0.35	< $0.1
MISO	2018	9.8%	-$0.31	9.8%	$1.90	$0.64

Table 2 shows that virtual trading generally improved price convergence between the day-ahead and real-time markets in ISO-NE because it was generally profitable. The average volume of cleared virtual transactions has increased gradually in recent years, which was due largely to reduced uplift charges to real-time deviations over the period. In spite of the increase, the virtual trading levels were still substantially lower than the levels observed in both the NYISO and the MISO. In 2018, the gross volume of cleared virtuals (including both virtual load and virtual supply) averaged roughly 7 percent of load in the ISO-NE market, compared to 18 percent in the NYISO market and nearly 20 percent in the MISO market.

Most of the differences shown in the table between ISO-NE and the other RTOs continue to be attributed to 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. This provides a substantial disincentive for firms to engage in virtual trading because virtual profits tend to be small relative to day-ahead and real-time prices. Ultimately, this reduces liquidity in the day-ahead market and explains why the gross profitability of virtual transactions is larger in ISO-NE than the other RTOs (i.e., the day-ahead and real-time prices are not as well arbitraged).

This may become a more substantial concern in the future. The ISO is currently considering a market design improvement, a Multi-Day Ahead Market, to address energy security concerns.[19] Virtual trading will play a essential role in aligning prices in the multi-day ahead market with the prices in the real-time market. Hence, we continue to recommend the ISO modify the allocation of Economic NCPC charges to be more consistent with a "cost causation" principle, which would involve not allocating NCPC costs to virtual load and other real-time deviations that cannot reasonably be argued to cause real-time economic NCPC.

B. Drivers of Day-Ahead NCPC Charges

Day-ahead NCPC charges are incurred when a resource is scheduled in the day-ahead market, but the revenues it receives from selling energy are not sufficient for it to recoup its as-offered start-up, no-load, and incremental costs. In addition to clearing day-ahead bids and offers in the day-ahead market, ISO-NE also commits resources in the day-ahead market to satisfy all of its forecasted reliability needs for the following day. Thus, 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).

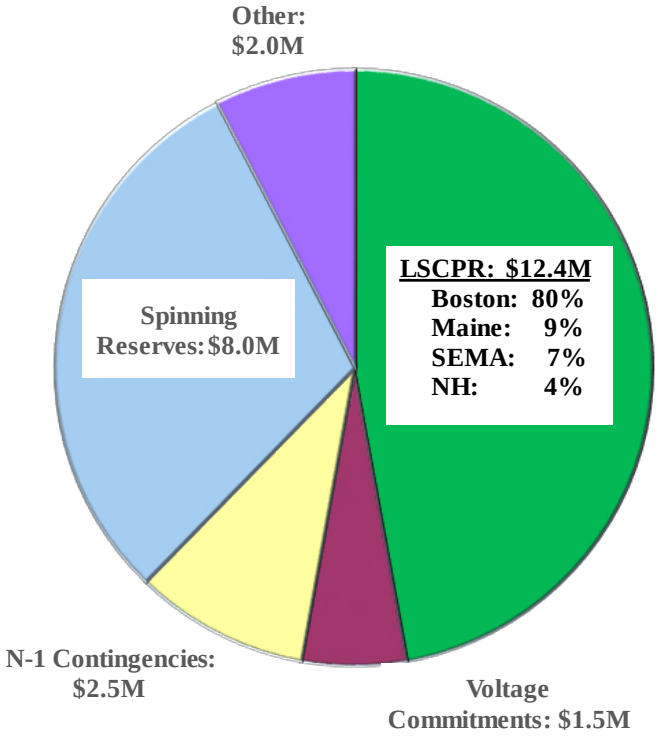
Satisfying reliability requirements in the day-ahead market is more efficient than waiting until after the day-ahead market clears because reliability commitments affect which resources should be committed economically in the day-ahead market. For example, if a 400 MW generator must be committed for reliability in a particular load pocket, the generator also helps satisfy demand

[19] See ISO Discussion Paper "Energy Security Improvements", April 2019.

throughout the system so it will likely reduce the amount of resources that are economic to commit outside the load pocket.

To summarize the causes of day-ahead NCPC, Figure 8 shows NCPC charges in 2018 incurred for the following reasons: local second contingency protection, voltage support, local single contingency protection, system-level reserve requirement, and other.[20] The figure also provides regional subtotals for local second contingency protection.

Figure 8: Summary of Day-Ahead NCPC Charges by Category
2018



The largest contributor to NCPC charges in the day-ahead market is commitments to satisfy local second contingency requirements, primarily in Boston. The next largest contributor is commitments to satisfy system-level ten-minute spinning reserve requirements. The market effects of these commitments are analyzed later in this section – local second contingency commitments are evaluated in Subsection C, and commitments for system-level ten-minute spinning reserves are evaluated in Subsection D.

20 *Local second contingency protection resources* are committed to maintain sufficient reserves to protect an area in case the two largest contingencies were to occur in a 30-minute period. *Voltage support resources* are committed to maintain local voltage or resolve a reactive power requirement. *Local first contingency protection resources* are committed to maintain transmission security in case a contingency was to occur unexpectedly. *System-level reserve requirements* are defined for TMSR, TMNSR, and TMOR, and resources may be committed to satisfy those requirements in the day-ahead market.

One notable factor that leads to inefficient commitments for local reliability, depressed clearing prices, and increased NCPC charges is that some combined-cycle generators are offered in a multi-turbine configuration even though they are able to operate the turbines individually. In many cases, the reliability requirement could be satisfied with the commitment of a single turbine configuration, so needlessly committing the multi-turbine configuration displaces other more efficient generating capacity. Multi-turbine combined-cycle commitments accounted for:

- More than 50 percent of the capacity committed for local reliability in the day-ahead market in 2018; and
- Roughly 60 percent of day-ahead local second contingency NCPC payments.

We evaluate the market effects of these excess commitments in 2018 in Subsection C.

C. Day-Ahead Commitment for Local Second Contingency Protection

The ISO commits resources for local second contingency protection needs in the day-ahead market. The purpose of these commitments is to ensure that ISO-NE can reposition the system in key areas to be able to respond to the second largest system contingency after the largest contingency has occurred.

While these commitments may be justified from a reliability perspective, they can lead to inefficient prices in the local area for two reasons:

- First, the units receiving NCPC payments systematically receive more revenues than lower-cost resources.
- Second, the costs of these resources will not be reflected in the prices of the operating reserves that are also satisfying the underlying reliability requirement.

These two issues distort economic incentives in favor of high-cost units with less flexible characteristics because, all else equal, they receive higher revenue than lower-cost more flexible units. Hence, when local NCPC is substantial, it is important to identify the underlying causes and consider market reforms as needed to improve the efficiency of prices for energy and operating reserves in local areas.

These concerns are sometimes exacerbated by two other issues that can lead to excess commitment for local second contingency protection.

- First, the day-ahead commitment software does not model the full set of energy and operating reserve requirements, particularly when the commitment of a large unit will alter one of the contingencies for which the software is scheduling. The ISO represents these factors indirectly in the day-ahead commitment logic, but this does not minimize costs because the procurement of operating reserves is not co-optimized with energy.
- Second, some generators that are 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.

Of capacity that was committed by the day-ahead market model for local second contingency protection in Boston in 2018, we estimate that roughly 60 percent of the capacity would not have been needed to satisfy the local second contingency requirements modeled in the day-ahead market if energy and operating reserves had been co-optimized with the requirement.[21]

The ISO could avoid excess commitment by: (a) implementing ancillary services markets that are co-optimized with energy in the day-ahead market, and (b) modifying its tariff to require capacity suppliers to offer multiple unit configurations to allow the ISO to commit just one turbine at a multi-turbine group. Not only would these changes result in production cost savings and more efficient prices for energy and reserves as discussed above, but they would also improve market incentives for reliable performance, flexibility, and availability under a wide range of conditions—not just operating reserves shortages. Directing more revenue to generators that have these characteristics would shift investment accordingly and reduce reliance on the capacity market for attracting investment to local areas.

Finally, satisfying these local requirements through a day-ahead operating reserve market should substantially reduce the need to commit resources out-of-market in the local areas that currently receive sizable NCPC payments. These NCPC payments provide adverse fuel procurement incentives. Under the market power mitigation rules, a generator that is committed for reliability can make more money by operating on a more expensive fuel because the relevant offer cap is calculated as a percentage over the generator's estimated cost.[22] For example, one dual-fuel generator in Boston operated on fuel oil for 19 days in 2018 when natural gas was less expensive than fuel oil.[23] Enforcing a requirement that generators committed for reliability burn the most economic fuel will reduce the frequency of commitments that require substantial NCPC payments. Ultimately, this will improve price signals for energy and reserves, and lower costs for the ISO's customers.

D. Day-Ahead Commitment for System Level Operating Reserve Requirements

As discussed in Subsection B, the day-ahead market software commits sufficient resources to satisfy system-level operating reserve requirements in addition to energy schedules. However, these reserve requirements are not enforced in the day-ahead market pricing software because ISO-NE currently does not have day-ahead reserve markets. Consequently, generators are

21 Note, this evaluation considered only local second contingency protection commitments in Boston that were made by the day-ahead market's commitment software, but it does not include commitments that were determined by operations before the day-ahead market. When interpreting these results, it is also important to consider that local second contingency protection units might still have been committed for another constraint even if they were not needed specifically to satisfy the minimum capacity requirement for the local area.

22 See Section III.A.5.5.6.2. of the ISO Tariff.

23 See EPA Air Markets Program Data at https://ampd.epa.gov/ampd/.

frequently committed in the day-ahead market to satisfy operating reserve requirements, but the clearing prices of energy (and reserves) are understated because they do not reflect the costs of satisfying the reserve requirements. We estimate that:

- Additional generating capacity was committed to satisfy the system-level 10-minute spinning reserve requirement in approximately 3,900 hours in 2018.[24]
- Pricing these operating reserve requirements in the day-ahead market would provide efficient compensation for resources providing ten-minute spinning reserves.

Setting more efficient prices for energy and spinning reserves would provide better incentives for reliable performance, flexibility, and availability. This will become increasingly important as the penetration of intermittent renewable generation increases over the coming decade. Under-compensating generators that have flexible characteristics shifts investment incentives towards other types of resources and increases dependence on the capacity market for attracting the investment necessary to maintain reliability.

E. Drivers of Real-Time NCPC Charges

Real-time NCPC charges are incurred when a resource is scheduled in the real-time market, but the revenues it receives are not sufficient for it to recover its as-offered commitment and dispatch costs.[25] Table 3 summarizes real-time NCPC charges in 2018 for the following categories based on their allocations:

- Local Reliability – Units that receive NCPC credits in this category are committed or dispatched to primarily satisfy the second contingency protection or the voltage requirements in the local area. This NCPC uplift is allocated to local loads.
- External Transactions – Transactions are scheduled based on their offer prices, but they receive NCPC credits if real-time prices are below their offer. This NCPC uplift is allocated to real-time deviations at the proxy bus (excluding CTS transactions).
- Market-Wide Charged to Real-Time Load Obligation ("RTLO") – These are the economic NCPC uplifts that are charged to market-wide load based on their real-time load obligations, including:
  - Generator Performance Audit – Paid to generator for audits initiated by the ISO.
  - Dispatch Lost Opportunity Cost – Paid to a resource instructed by the ISO to run at a level less than its economic dispatch point.
  - Rapid-Response-Pricing Opportunity Cost – Paid to a resource that is postured down when a rapid-response resource is setting price, which compensates the resource for

24 We found very few hours in 2018 when additional capacity was committed to satisfy the total 10-minute reserve and 30-minute reserve requirements. This is likely because New England has sufficient offline fast start capacity to satisfy these requirements in the vast majority of hours.

25 This includes opportunity costs if a generator would have earned more by not following the ISO's instructions.

the difference between the amount it would have earned for energy and reserves absent being postured down.

- Resource Posturing – Paid opportunity costs to resources that are held in reserve for reliability even when it would be more profitable to generate.

- Market-Wide Charged to Real-Time Deviation – These are the economic NCPC uplifts charged to market-wide real-time deviations, which include deviations from generation, load, external transaction, and virtual transactions.
  - Fast Start Resources – These are fast start resources that are committed primarily by the look-ahead model, but do not set price because they are uneconomic in the dispatch model.
  - Supplemental Commitment after DAM – These are non-fast-start units that are committed after the day-ahead market for reliability.
  - Other – These include NCPC credits that resulted from actions by the ISO (e.g., cancel the start of a resource, instruct a resource for regulation) and ramping limitations of resources when following dispatch.

Table 3: Summary of Real-Time NCPC Charges by Category
2018

Real-Time NCPC Category	Charges (Million $)	Share of RT NCPC
Local Reliability		
Local Second Contingency	$0.6	1%
Voltage Support	$0.4	1%
SCR	$0.6	1%
Multi-Turbine Portion	$2.7	6%
External Transactions	$2.7	6%
Market-Wide *Charged to RTLO*		
Generator Performance Audit	$1.4	3%
Dispatch LOC	$3.7	8%
Rapid Response OC	$4.0	9%
Resource Posturing	$10.1	23%
Market-Wide *Charged to RT Deviation*		
Fast Start Resources	$6.9	16%
Supplemental Commitment after DAM	$6.3	14%
Other	$4.4	10%
Total	$43.9	

Local Reliability Real-Time NCPC

Local reliability requirements and other supplemental commitments after the day-ahead market accounted for a relatively small share (collectively 23 percent) of real-time NCPC in 2018. This was down from prior years because of reduced need to commit generation for local Boston-area reliability following transmission upgrades and the market entry of the Footprint combined-cycle plant.

Real-Time NCPC for Posturing and Fast-Start Resources

Resouce posturing accounted for the largest share of real-time NCPC in 2018, although nearly 70 percent of this occurred in early January 2018 during the cold snap because of fuel limitations. Posturing NCPC can provide perverse incentives by allowing resources to earn more profit by running short of fuel and receiving NCPC than they could from procuring fuel and consuming it to produce electricity. This is because they receive NCPC equal to the difference between the LMP and their offer for the duration of the posturing. Thus, if a generator has only three hours of fuel left and it is postured by the ISO for 12 hours, it will be paid for 12 hours of opportunity costs (i.e., estimated lost profits). This is far more than the profit it would make from generating for three hours.

NCPC for resource posturing was very limited in winter 2018/19 because of milder weather conditions and lower gas prices. Furthermore, the ISO implemented a market enhancement in December 2018 that allows opportunity costs associated with short-term fuel supply limitations for oil-fired and dual-fuel units to be included in their reference levels. This should help resources more accurately reflect opportunity costs in their offers and enable better commitment and dispatch through the market (rather than out-of-market actions such as posturing).

Fast start resources accounted for the second largest share of real-time NCPC in 2018. These resources were committed primarily by the look-ahead market model (i.e., the Generation Control Application) based on forecast system needs. However, forecast errors frequently led these resources to be uneconomic under actual real-time prices, resulting in NCPC charges.

Allocation of Real-Time NCPC

It is important to allocate NCPC charges in an efficient manner. However, most of the NCPC charges that are allocated to real-time deviations are not caused by real-time deviations. Specifically, supplemental commitment for market-wide reliability after the day-ahead market is the only category that is driven partly by real-time deviations and this accounted for just 36 percent of real-time NCPC charges in 2018 that were allocated to real-time deviations. This is similar to our finding in prior years. These commitments are sometimes caused by under-scheduling of energy in the day-ahead market or the loss of a significant supply resource after the day-ahead market. So, real-time deviations that reduce scheduling of physical resources in the

day-ahead contribute to this category of NCPC charges, which includes virtual supply, under-scheduled load, or a generator that experiences a forced outage after the day-ahead market.

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 of load in the day-ahead market. Over-allocating NCPC charges to real-time deviations has provided strong disincentives for participation by virtual traders in the ISO-NE market as discussed in Subsection A. Hence, costs should only be allocated to real-time deviations to the extent that they cause the costs and the balance should be allocated to load.

F. Conclusions and Recommendations

In our assessment of day-ahead NCPC charges, we found that in 2018, 47 percent was attributable to commitments for local second contingency protection, while 30 percent was attributable commitments for the system-level 10-minute spinning reserve requirement. Both of these requirements are satisfied by scheduling operating reserves, but operating reserves are not procured in the day-ahead market and the cost of scheduling operating reserves is not reflected efficiently in energy prices. The absence of a co-optimized day-ahead operating reserve market resulted in:

- Excess commitments by the day-ahead market model for local second contingency protection in Boston, 60 percent of which would not have been needed under a co-optimized energy and reserve market.
- Depressed clearing prices for energy and 10-minute spinning reserves providers (by approximately $1.00 to $1.50 per MWh on an annual average basis). We estimate there were 3,900 hours when additional generation was committed to satisfy the system level 10-minute spinning reserve requirement, which was not reflected in prices.

In addition, we continue to find that NCPC costs are inflated when the ISO is 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.

We make two recommendations to improve the pricing of energy and operating reserves.

- We recommend that the ISO co-optimize the scheduling and pricing of operating reserves in the day-ahead market.
- We recommend the ISO expand its authority to commit combined-cycle units in a single-turbine configuration when that will satisfy its reliability need.

ISO-NE has started several initiatives to address energy security concerns, including co-optimizing procurement of energy and operating reserve in the day-ahead market. We support

this effort and expect it will address a number of the issues we identified and discussed in this section.

One advantage to co-optimizing the scheduling of energy and operating reserves in the day-ahead market is that it would facilitate the elimination of the forward reserve market. As in prior years, nearly all of the resources assigned to satisfy forward reserve obligations in 2018 were fast-start resources capable of providing offline reserves. The value of the forward reserve market is questionable because:

- It has not achieved its objective to lower NCPC by purchasing forward reserves from high-cost units frequently committed for reliability.
- The forward procurements do not ensure that sufficient reserves will be available during the operating day.

The obligation of forward reserve suppliers to offer at prices higher than the Forward Reserve Threshold Price can distort the economic dispatch of the system and inefficiently raise costs.

In assessing the real-time NCPC charges, we found that just 14 percent of the real-time NCPC can be attributed to real-time deviations, although 40 percent of all real-time NCPC are allocated to these deviations. Hence, we find that ISO-NE currently over-allocates real-time NCPC charges to virtual transactions and other real-time deviations. This has substantially reduced virtual trading activity and the overall liquidity of the day-ahead market compared to other RTO markets. We recommend that the ISO modify the allocation of Economic NCPC charges to be more consistent with a “cost causation” principle, which would largely involve not allocating NCPC costs to virtual load and other real-time deviations that do not cause it.

IV. FUEL SECURITY IN NEW ENGLAND

The New England region has become increasingly reliant on natural gas as nearly 5 GW of new fuel-efficient conventional generation have been built and 5 GW of nuclear, coal-fired, and older steam turbine capacity have retired in the first 13 Forward Capacity Auctions. The share of installed capacity that is primarily natural gas-fired has risen from 47 percent to 67 percent over this timeframe. ISO-NE has frequently raised concerns about the increasing reliance on gas-fired generation in recent years, and the ISO has studied the region's vulnerability to fuel security reliability issues as part of its Operational Fuel Security Analysis ("OFSA").

After the announcement of the proposal to retire Mystic units 8 and 9 and the Distrigas LNG-import terminal, the ISO used the OFSA model to evaluate the fuel security reliability of New England if the Mystic units and the Distrigas facility were retired ("Mystic Retirement Study").[26] The study found tight fuel supply margins during periods of extended cold weather that would result in load shedding in winters of 2022/23 and 2023/24. Likewise, we performed an analysis which found that even with very high utilization of oil inventory capacity and LNG import capability, New England would experience load shedding in a pipeline contingency or in a scenario with major reductions in availability of LNG or oil inventories.[27]

In light of these reliability concerns, ISO-NE: (a) entered into out-of-market contracts to retain Mystic units 8 and 9 (which require the continued operation of the Distrigas terminal) for two years, (b) filed a proposal to create a short-term compensation mechanism for units that maintain firm fuel inventories for the Capacity Commitment Periods for FCA 14 and FCA 15, and (c) is currently working with its stakeholders to design long-term market-based solutions for addressing the fuel security issues. Ultimately, the goal of this effort is to replace the temporary mechanism and the need for out-of-market contracts with a market that channels investment in the most efficient mix of resources for satisfying the reliability needs of the system.

This section builds on previous studies by analyzing how the aforementioned market design enhancements are expected to affect:

- Fuel security reliability during extreme weather and potential supply contingencies, and
- Whether out-of-market contracts for fuel security might be necessary again in the future.

Subsection A discusses these issues in the Capacity Commitment Period for FCA 13, while Subsection B evaluates fuel security in 2024/25 after the contract for the Mystic units expires.

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26 See ISO's May 1, 2018 *Petition of ISO New England Inc. for Waiver of Tariff Provisions* in Docket No. ER18-1509-000.

27 See *2017 Assessment of the ISO New England Electricity Markets* by Potomac Economics.

A. Fuel Security Outlook for Winter 2022/23

The ISO is designing rules to provide market incentives for suppliers to acquire the fuel necessary to maintain reliability during periods of natural gas scarcity.[28] In the long-term (i.e., years for which FCAs have not yet been held), these changes should provide incentives for investment in new resources and maintenance of existing resources that are fuel secure. In the short-term, these changes should improve incentives to procure fuel and fully utilize the existing generation to maintain reliability. This section discusses our analysis, which used the ISO's OFSA model to evaluate how the new market rules are expected to affect fuel security reliability during the Winter 2022/23—the last period for which an FCA has been conducted.

The ISO's default assumptions in the OFSA model are very conservative about oil tank replenishment rates and dispatch order, which are based on its past experience. However, the ISO's market design enhancements will provide incentives for generators to act differently in the future. These rules will encourage replenishment and lead to a dispatch order that will help conserve limited fuel inventories. If expected behavior is not modeled accurately, it could overstate the severity of fuel security issues and lead to additional out-of-the market contracts. Accordingly, we requested the ISO run the OFSA model with modifications to the following two default assumptions. The ISO incorporated these two methodological and resource mix changes and provided us the model results for the winter of 2022/23.[29]

- *Light oil units (i.e., combined cycles) are always dispatched before heavy oil units (i.e., older steam turbines).* Although this is expected under normal operating conditions, the ISO's fuel security review is designed to determine whether load shedding would occur under very stressed conditions that have not occurred in the past. Under stressed conditions, light oil units tend to be more limited than heavy oil units by tank capacity, potential refueling rates, and emissions permit limitations. Efficient incentives would encourage units with limited inventories to conserve fuel, which would lead units with larger inventories to produce more. Thus, we requested the ISO reverse the dispatch order in this analysis to simulate efficient incentives to conserve fuel inventories.
- *Oil-fired and dual-fuel generators will not fill their oil tanks to capacity before each winter or fully utilize refueling capacity during the winter.* For light oil units (i.e., combined cycles), this may not understate the units' availability given other limitations that are not explicitly modeled in the review (e.g., 30-day air permit restrictions). However, this assumption would greatly under-estimate the potential production levels of heavy oil units (i.e., older steam turbines),. Hence, we requested the ISO run the OFSA model assuming the market design changes induce more refills of oil tanks.

28 See ISO's May 7, 2019 presentation to Markets Committee *Energy Security Improvements: Market-based Approaches.*

29 See FCA-13 new entry and retirements in *Forward Capacity Auction Obligations*, available at https://www.iso-ne.com/isoexpress/web/reports/auctions/-/tree/fca-results. The total capacity we assumed to be retired in our analysis is roughly 50MW less than the capacity that retired or delisted in FCA-13.

Table 4 shows the assumptions and model results for five scenarios that are based off of an original ISO Reference case that used the resource mix from FCA 12. The table also shows the results for several large contingency scenarios that have been identified in the ISO's fuel security studies.[30]

Table 4:Fuel Security Analysis with Modified Assumptions[31]
Winter 2022/23

Scenario Description	No.	Assumptions				Results (Hrs)		
		New Entry and Retirements	Dispatch Order	Oil Tank Refills	LNG (bcf/d)	30 Min Res Depletion	10 Min Res Depletion (< 700MW)	Load Shedding
ISO Ref + Updated Resource Mix	[1]	FCA-13 New Entry/ Retirements	ISO default	1.25	0.8	138	12	2
[1] + Modified Dispatch	[2]	FCA-13 New Entry/ Retirements	CCs after ST units	1.25	0.8	24	0	0
[2] + Modified Refills (*EMM Reference*)	[3]	FCA-13 New Entry/ Retirements	CCs after ST units	Heavy - Unlimited Light - 2	0.8	0	0	0
[3] with Batteries Replacing a ST	[4]	FCA-13 New Entry/ Retirements + 600MW of batteries in place of ST	CCs after ST units	Heavy - Unlimited Light - 2	0.8	2	0	0
Contingencies								
EMM Ref [3] - Millstone outage	[5]	FCA-13 New Entry/ Retirements - Millstone out for 14 peak days	CCs after ST units	Heavy - Unlimited Light - 1	0.8	36	0	0
EMM Ref [3] - Pipeline outage	[6]	FCA-13 New Entry/ Retirements - 1.2 bcf/d gas unavailable for 14 peak days	CCs after ST units	Heavy - Unlimited Light - 1	0.8	57	1	0
EMM Ref [3] - Canaport outage	[7]	FCA-13 New Entry/ Retirements - Canaport out for 14 peak days	CCs after ST units	Heavy - Unlimited Light - 1	0.4	14	0	0

In Scenario 1 simply updates the ISO Reference case to reflect recent resource mix changes. In this scenario, the OFSA model finds significant reliability issues, including two hours of load shedding, twelve hours of 10-minute reserve depletion to 700 MW, and 138 hours of 30-minute reserve depletion. The other scenarios shown in Table 4 indicate that the market design changes being developed by the ISO will substantially affect reliability:

- Scenario 2 (modifying the dispatch so that heavy oil units are scheduled before the more fuel-constrained light oil units) eliminates load shedding and 10-minute reserve

30 See ISO's January 17, 2018 *Operational Fuel-Security Analysis*. Also see ISO's May 1, 2018 *Petition of ISO New England Inc. for Waiver of Tariff Provisions* in Docket No. ER18-1509-000

31 We assume imports from external control areas to be at 2800 MW for all the scenarios in Table 4.

depletion, and reduces the frequency of 30-minute reserve depletion by 83 percent. Scenario 3 shows that incentives for frequent refills would eliminate even 30-minute reserve depletion.

- The system would be far more reliable even under contingency scenarios with significant reductions in supply. For example, Scenario 5 reveals that replacing 560 MW of heavy oil units with short duration batteries would result in just two hours of 30-minute reserve depletion.
- None of the extraordinary contingencies considered would result in load shedding hours in the *EMM Reference* scenario. These contingencies result in only one hour where 10-minute reserves are depleted to a level below 700 MW and no hours of load shedding.

As the resource mix in New England changes, it is important to consider how battery storage resources are likely to affect fuel security reliability. Battery storage resources have the potential to provide considerable flexibility to the system, particularly under high renewable penetration conditions. As we discuss in Section V, battery storage resources are well-positioned to earn high levels of capacity revenue as a result of the Pay-For-Performance rules. The interconnection queue currently includes over 2.5 GW of battery storage resources, driven in part by state public policy goals. However, batteries are energy limited resources that have very little fuel security value. Hence, the market design enhancements to promote fuel security will become increasingly important as battery storage resources enter the market.

Although the analysis in this section suggests that market design changes will be sufficient to ensure fuel security reliability even under extreme contingency scenarios, the next section examines the outlook if the Mystic and Distrigas facilities retire.

B. Fuel Security Outlook for Winter 2024/25

ISO-NE entered into an out-of-the-market contract with the owner of Mystic units 8 and 9 (and the Distrigas LNG-import terminal) after finding that their retirement would lead to significant fuel security reliability risks. The contract with Mystic 8 and 9 is for two years and ends after CCP 2023/24. As discussed in the previous subsection, the ISO is developing market design enhancements that will be critical for bolstering reliability during severe winter conditions. In this subsection, we incorporate several changes into the fuel security reliability assessment of 2024/25 winter to simulate the effects of the market design enhancements that are currently under development. These include:

- Deploying heavy oil units ahead of light oil units (when light oil units have more limited oil inventories) – Under tight fuel supply conditions, an efficient market design will motivate units with limited inventories to conserve their remaining fuel, leading units with larger inventories to be deployed first;

- More frequent refilling of oil inventories – Under tight fuel supply conditions, an efficient market design will motivate dual fuel units to maintain higher inventories and refuel more frequently; and
- Higher utilization of existing LNG-import capacity – If a major fuel source is lost, an efficient market design will induce generators and natural gas shippers to contract with LNG-importers to increase supplies to the region.

Table 5 shows the assumptions and results for several winter 2024/25 scenarios that are based on varying assumptions about the state of Mystic units and LNG injection rates:

- Scenario 2 shows an injection rate of 0.4 Bcf/day based on the assumption that the loss of Distrigas would not lead to any incremental increase in LNG imports to the other two import-terminals in the region;
- The higher injection rates shown in Scenarios #3 to #6 are based on the assumption that the loss of Distrigas would likely encourage increased imports to the other terminals.

Table 5: Fuel Security Analysis with Retirement of the Mystic and Distrigas Facilities[32]
Winter 2024/25

Scenario Description	No.	Assumptions			Results (Hrs)		
		New Entry and Retirements	Oil Tank Refills	LNG (bcf/d)	30 Min Res Depletion	10 Min Res Depletion (< 700MW)	Load Shedding
EMM Reference 2024/25	[1]	FCA-13 New Entry/ Retirements	Heavy - Unlimited Light - 2	0.8	0	0	0
Sensitivities on LNG Injection for Mystic 8 and 9 and Distrigas LNG Retirement Scenario							
LNG Sensitivity #1 (Low Injection)	[2]	FCA-13 New Entry/ Retirements - Mystic 8 and 9 + Distrigas LNG retired	Heavy - Unlimited Light - 2	0.4	216	2	0
LNG Sensitivity #2	[3]			0.5	146	2	0
LNG Sensitivity #3	[4]			0.6	95	0	0
LNG Sensitivity #4	[5]			0.7	52	0	0
LNG Sensitivity #5 (High Injection)	[6]			0.8	23	0	0

32 We assume imports from external control areas to be at 2800 MW for all the scenarios in Table 5.

As was the case with EMM Reference scenario in 2022/23, we continue to find no significant fuel security issues in 2024/25 if the dispatch order and replenishment assumptions reflect the proposed market design changes (EMM Reference 2024/25). However, Scenario #2 in Table 5 indicates that the retirement of the Mystic and Distrigas facilities would lead to two hours of 10-minute reserve depletion to 700 MW and frequent 30-minute reserve depletion (if there was no market response to the shortages from LNG importers).

Ultimately, the impact of retiring the Mystic and Distrigas facilities would depend on the response from other sources of supply, so we evaluated the reliability impact of increasing supply in response to the retirements. Scenarios #3 to #6 in Table 5 show that if the volume of LNG imports through the other two import terminal rose from 0.4 to 0.8 Bcf/day, reserve shortages would become much less frequent. Scenario #6 shows that increasing LNG imports to 0.8 Bcf/day, replacing slightly more than half of the gas supply lost from retiring Mystic and Distrigas, reduces the frequency of 30-minute reserve depletion to 23 hours and eliminates 10-minute reserve depletion to 700 MW.

Although load shedding does not occur under any of the scenarios listed in Table 5, these scenarios do not consider the effects of a large supply contingency (besides Mystic and Distrigas), such as a pipeline contingency. Hence, it is unclear how much additional supply could be lost before New England would experience serious reliability issues. In the coming years, new resources with low fuel security value (e.g., battery storage) may replace generation with high fuel security value (e.g., oil-fired steam turbines), which would increase fuel security reliability risks. Hence, developing a market mechanism to reward fuel security would provide valuable incentives to support the development and maintenance of fuel secure resources, which can reduce or eliminate entirely the reliability impact of the retirement of Mystic and Distrigas.

C. Conclusions and Recommendations

The ISO's Operational Fuel Security Assessment ("OFSA") model was developed to evaluate the planning reliability needs of New England with explicit consideration of fuel supply limitations of individual generators. This innovative model is the first of its kind, but we are concerned that it relies on some assumptions that are overly conservative by assuming that the market will not respond with additional fuel supplies under shortage conditions. Consequently, the OFSA model may indicate the need for additional installed capacity to address a fuel security issue that could be fully resolved through market design enhancements that motivate resource owners to procure additional fuel supplies.

The market design enhancements being developed by the ISO will compensate resources for holding inventories during tight fuel conditions and provide incentives that help the region conserve fuel supplies. Our analysis in this Section indicates that these enhancements will substantially improve reliability under conditions that raise fuel security concerns. These

reliability improvements are due to enhanced incentives that will lead to improvements in the operation of the system and decisions by suppliers, including:

- Deploying heavy oil units ahead of light oil units;
- More frequent refilling of oil inventories; and
- Higher utilization of existing LNG-import capacity.

We evaluated two timeframes, one before the Mystic Units retire and one after the Mystic retention contract expires and the units are assumed to have retired:

- Winter 2022/23 – This is the Capacity Commitment Period ("CCP") corresponding to the Forward Capacity Auction that was held in February 2019 (i.e., FCA 13). In this timeframe, we found that the improved fuel procurements by suppliers and operation of the system that should be motivated by the market enhancements are likely to effectively address New England's fuel security concerns. These results highlight the reliability improvements that are possible without any capacity additions.
- Winter 2024/25 – This is the first winter after the Mystic retention contract expires (i.e., FCA 15). The improvements described above would eliminate 10-minute reserves depletion and load shedding after the Mystic units retire. However, these scenarios did not consider the effects of additional supply contingencies (such as a pipeline contingency), so it is still unclear how much additional supply could be lost before New England would experience serious reliability issues.

These results underscore the importance of the market enhancements being developed by the ISO. These market design enhancements will provide strong incentives for resources to procure fuel necessary to maintain reliability under peak conditions, and increase the utilization of existing equipment for storing oil and importing LNG. This would not only likely eliminate reliability issues during extreme winter conditions, but also enable the ISO to maintain system reliability after the loss of a critical resource, such as the Millstone nuclear plant, a major pipeline, or an LNG import facility. In the longer-term, the ISO's market enhancements will facilitate longer-term improvements that will help address potential fuel security issues after the potential retirements of the Mystic units and the Distrigas LNG facility.

V. EVALUATION OF THE PAY-FOR-PERFORMANCE FRAMEWORK

The PFP rules were put in place to enhance incentives for suppliers to perform when they are needed the most. As part of the PFP rules, resources that provide more energy and/or operating reserves than the average capacity provider during a reserve shortage event are paid a Performance Payment Rate ("PPR"), while capacity suppliers that produce less than average are penalized according to the PPR. The Pay-for-Performance ("PFP") rules became effective on June 1, 2018.

In subsection A, we describe the conditions and settlements during the first PFP event that occurred since the rules became effective. In subsection B, we compare the compensation suppliers received during this event to the expected value of load that was at risk of not being served. In subsection C, we evaluate the incentives for energy storage resources under the current PFP and FCM rules, and identify a misalignment between their compensation and their value to the system.

A. First Pay-for-Performance Event

The first PFP event in New England occurred from 15:40 to 18:15 on September 3, 2018. Figure 9 depicts the event by showing the quantities of operating reserve shortages in the lower panel and the prevailing energy prices in the upper panel.

During the event, the shortage of 30-minute reserves ranged from 200 MW to 880 MW. The shortage resulted from a combination of factors that included unexpectedly high load (actual load exceeded forecast by ~2.5 GW), the sudden loss of the Mystic CCs due to a gas pressure issue (~1.4 GW), and other forced outages and deratings. As a result, the ISO cut Cross-Sound Cable exports to NYISO and made emergency purchases from NYISO and New Brunswick. In addition, up to 284 MW of Price-Responsive Demand was also activated.

During the event, the LMP at the Hub approached nearly $2,700/MWh (see Figure 9) in some five-minute intervals due to the shortage of 10-minute and 30-minute reserves.[33] In addition, resources that supplied energy or operating reserves were compensated (or charged) based on the PPR of $2,000/MWh. Therefore, a resource that produced energy or operating reserves during this event would have been compensated at a marginal rate of over $4700/MWh in some

[33] The Reserve Constraint Penalty Factor ("RCPF") is the value that the real-time market model places on satisfying a particular reserve requirement. The RCPF for the 30-minute reserve requirement is $1,000/MWh, and the RCPF for the 10-minute reserve requirement is $1,500/MWh, so a shortage of both types of reserves results in clearing prices of $1,000/MWh for 30-minute reserves and $2,500/MWh for 10-minute reserves, since 1 MW of 10-minute reserves contributes to meeting both requirements. LMP rose above $2,500/MWh, reflecting that one additional MW of energy would allow the model to back down an expensive generator to provide one additional MW of 10-minute reserves.

intervals. These compensation levels are much higher than the expected marginal value of lost load during the event, which we estimate in subsection B.

Figure 9: Energy Prices and 30-Minute Reserve Shortages during PFP Event
September 3, 2018

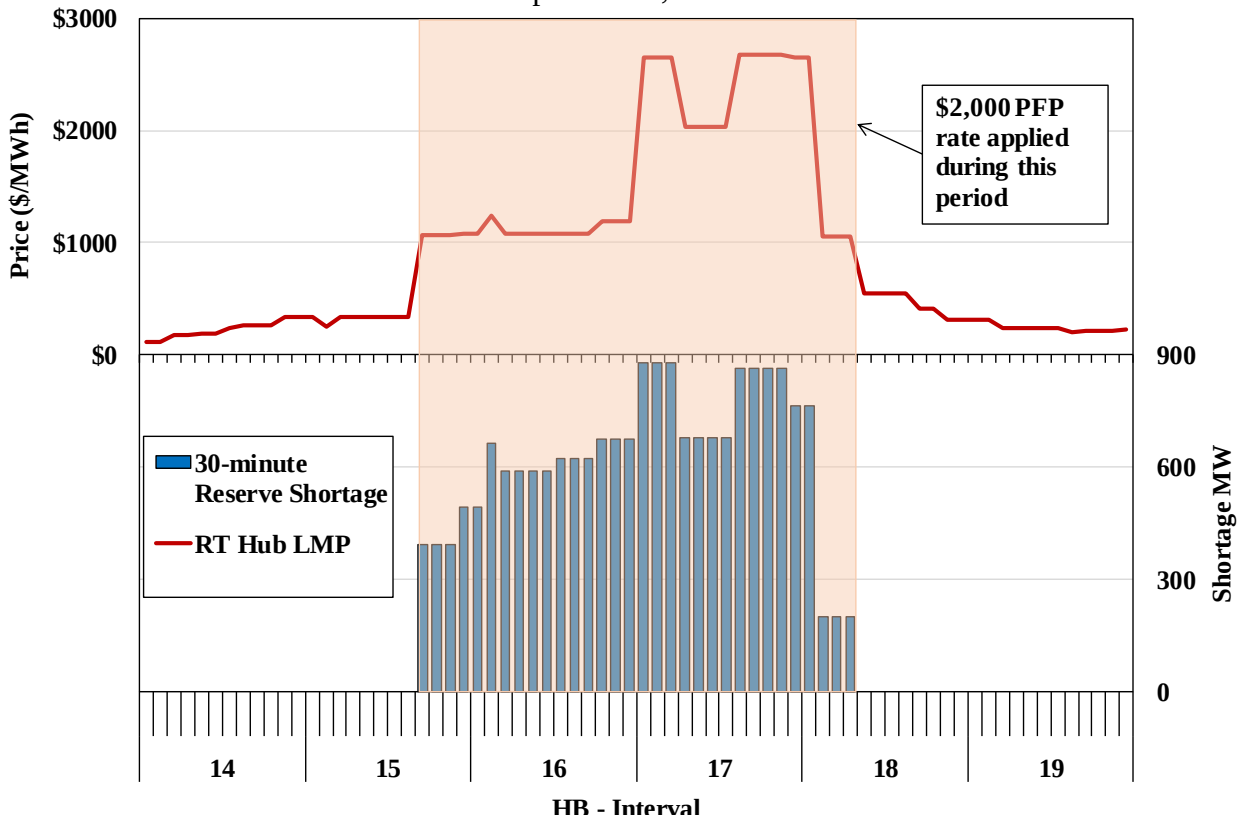
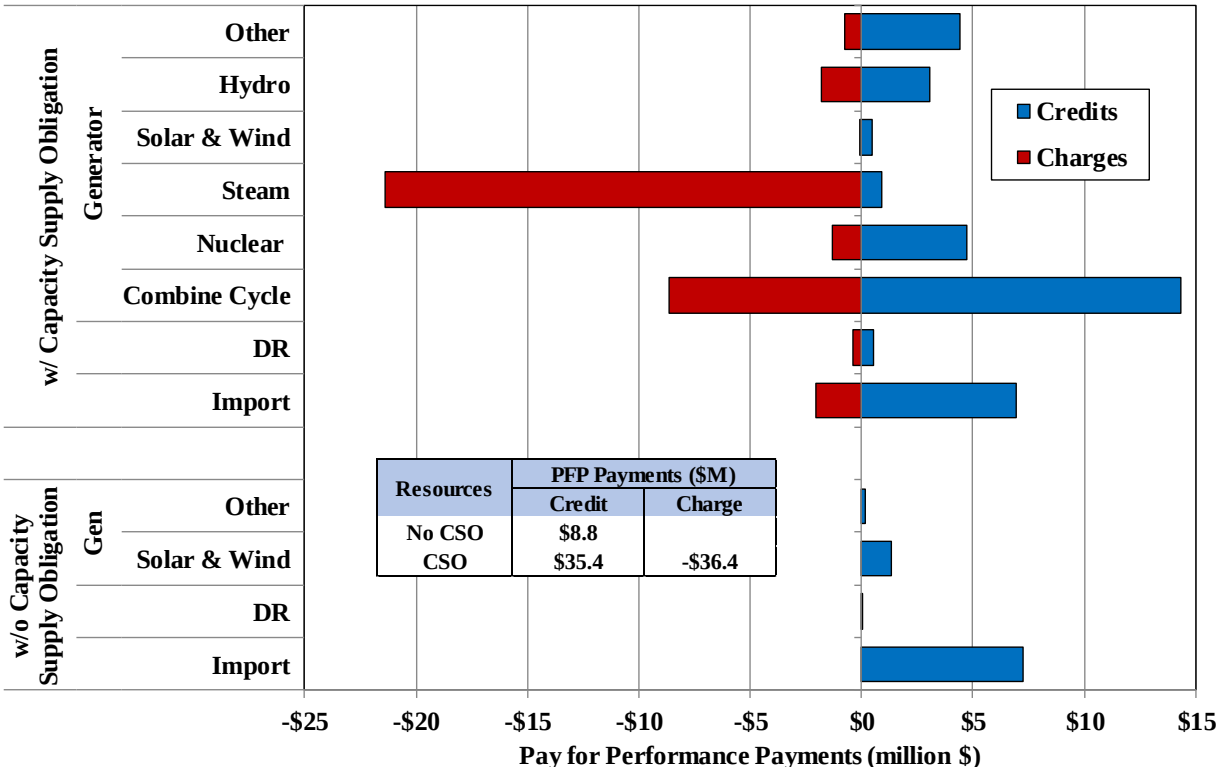


Figure 10 summarizes the settlement effects of the PFP event by type of unit. The total charges are shown in red while the payments are shown in blue. Charges are assessed to suppliers that are producing energy at levels that are less than their obligation, including those that are offline. Payments are made to suppliers producing more energy than their obligation, including those that have no obligation because they did not sell capacity. Payments to suppliers or importers that do not have a capacity obligation are shown separately in the figure.

Steam turbine units incurred the majority of the PFP penalties with total penalties of $22 million. Many of these units were not economic in the day-ahead market and could not respond to the event in real-time because of the units' long start-up times. Consequently, they generally performed below average and were subject to considerable PFP charges. On the other hand, every other category of resource performed above the fleet-wide average. Combined-cycle units with a CSO received more than $14 million in performance payments and paid almost $9 million in penalties on an aggregate basis. In addition, imports received performance payments of nearly $15 million, roughly half of which was paid to importers with no capacity obligations.

Figure 10: Settlements during the PFP Event
September 3, 2018



B. Evaluation of Pay-for-Performance Pricing

Efficient prices during reserve shortages play a key role in establishing economic signals to guide investment and retirement decisions in the long-run and facilitate efficient commitments and reliable performance in the short-run. In this subsection, we evaluate the efficiency of: (a) the shortage prices during the September 3, 2018 PFP event, and (b) the prices that would have occurred if the reserve shortages had been deeper during the event.

During shortages, efficient prices should be set consistent with several criteria. Specifically, prices should:

- Reflect the marginal reliability value of reserves given the shortage level;
- Depend on the risk of potential supply contingencies, including multiple simultaneous contingencies; and
- Rise gradually as the reserve shortage increases and have no artificial discontinuities that can lead to excessively volatile outcomes.

The marginal reliability value of reserves is equal to the expected value of the load that will not be served if the available reserves are reduced by 1 MW. The expected value of lost load ("EVOLL") during a reserve shortage event can be estimated as the product of: (a) value of lost

load ("VOLL"), and (b) the probability of losing load. We estimated (a) and (b) during the September 3, 2018 PFP event in the following manner:

- We assume a VOLL of $30k per MWh, which is on the high end of VOLL values that have been estimated;[34] and
- Given the resource mix and the reserve and energy output for each interval, we estimated the probability of losing load using a Monte Carlo simulation. This simulation incorporates the risk of concurrent generator forced outages during the PFP event to estimate the probability of 10-minute reserves falling to a level below 700 MW.[35]

Our simulation results indicate that the highest probability of losing load during the PFP event was only 3.3 percent per hour (Figure 11), which translates into approximately $1,000 per MWh of operating reserves. In contrast, resources that produced energy or reserves during this interval were compensated at a rate of over $4,700 per MWh. When the PPR reaches its maximum level in 2024/25, compensation for resources performing during a PFP event could exceed $7950 per MWh. Hence, the compensation to resources during shortages would substantially exceed the EVOLL in the vast majority of cases and would result in exaggerated shortage pricing that could motivate participants to take inefficient actions.

34 Estimates of the VOLL vary widely based on a range of demand-side factors that include the customer class being served, duration of the load shedding event, season/ timing of the event and geographical location of customers. A meta-analysis of reliability studies by LBNL and DOE estimated that in a one-hour power interruption, a small C&I customer (who may not have installed power back-up systems) could incur a cost per unserved kWh that is nearly 90 times the cost incurred by a residential customer. (See 2015 report on study tiltled *Estimated Value of Service Reliability for Electric Utility Customers in the United States*.) This study also estimated the cost of interruption for residential customers on a summer morning/ night could be nearly 4 times the cost of interruption on a non-summer evening. VOLL is also known to rise as the length of the outage increases, so a 16-hour long outage can cost an average large C&I customer nearly 22 times what a momentary outage would cost. Hence, VOLL is not a single value and varies considerably.

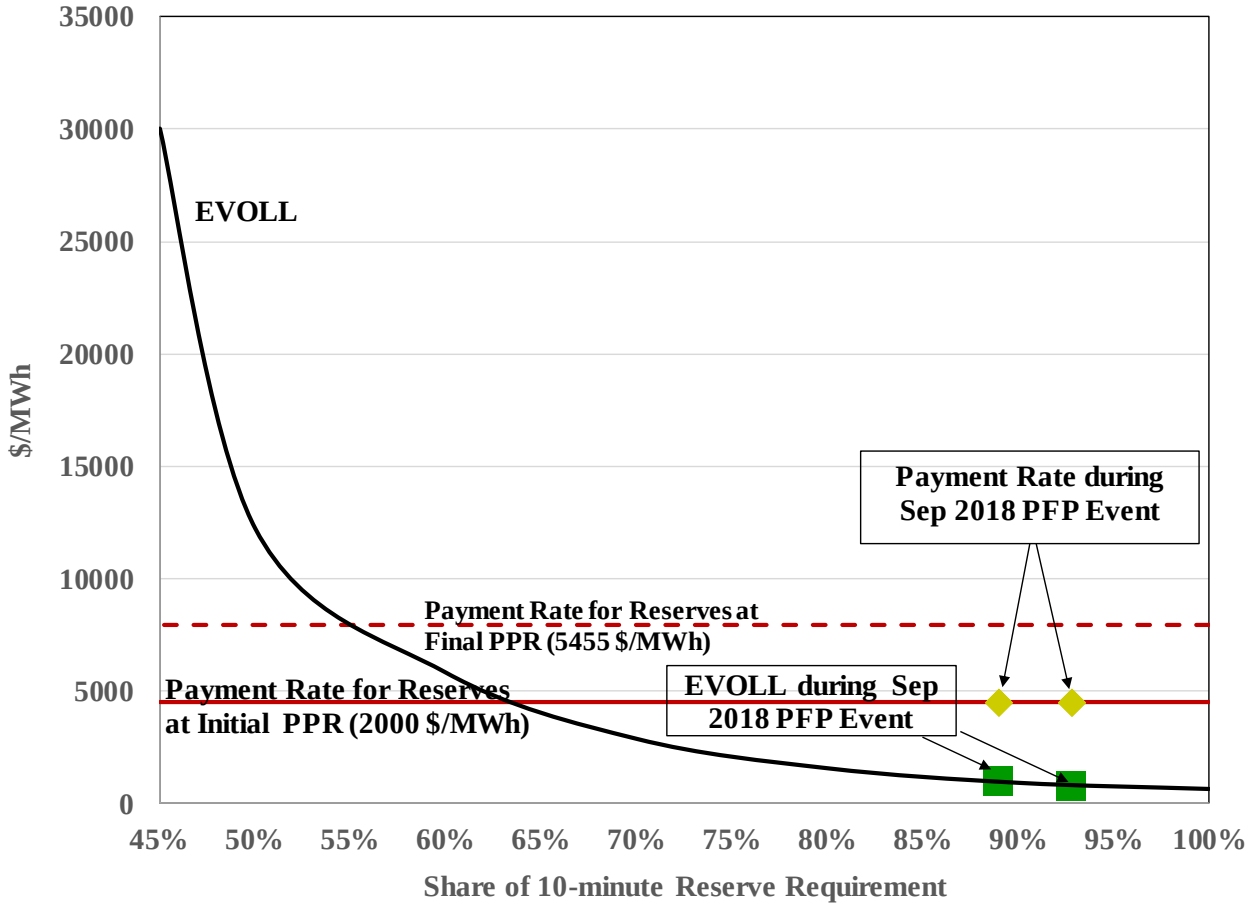
On the other hand, the VOLL that is implied by capacity market payments (estimated to be over $200,000 per MWh in several studies) is significantly higher than the VOLL across almost the studies (and across all key parameters discussed above). This is because capacity markets set capacity demand curves based on the estimated revenue necessary to satisfy certain reliability standards (rather than an evaluation of demand-side factors).

The ISO's planned PPR of $5455 per MWh is derived based on the following two principles: (a) a new entrant's expected FCM revenue should cover its Net CONE and any risk premium it requires to accept a CSO, and (b) a new or existing capacity supplier's FCM revenue should be zero if it expects to not perform during scarcity conditions. See ISO's September 4, 2013 memo to NEPOOL Markets Committee on *FCM Performance Incentives – Performance Payment Rate*. Hence, the ISO's PPR values are not necessarily related to the VOLL during reserve shortages.

35 We assumed that the time between generator forced outages is a random variable that follows a Poisson process. We assumed that the mean of the probability distribution is the corresponding class-average Mean Service Time to Unplanned Outage ("MSTUOs") derived from NERC GADS data. We used the MSTUO for each generator in our simulations to derive the probability that the generator would be on an outage during a two hour look-ahead window. See Section VI for assumptions underlying our analysis.

As the magnitude of the operating reserve shortage increases, the EVOLL increases because the probability of losing load increases. It is efficient for the prices to increase in accordance with the EVOLL because this will provide appropriate incentives for both suppliers and demand to take actions that are consistent with the reliability value of the actions. Therefore, we estimated how the implied EVOLL curves would change at various reserve shortage levels (using the Monte Carlo simulation results) and compared it to the compensation that suppliers would receive at that shortage level.

Figure 11: Comparison of Reserve Prices to EVOLL during PFP Events



The EVOLL curve (Figure 11) has a convex shape to it which indicates that the probability of losing load increases significantly during deeper reserve shortages than during shallow reserve shortages. However, the PPR and the RCPFs are flat and do not reflect this shape. Our results indicate that the combined rate of compensation would be far higher than efficient price levels during shallow shortages and much lower during deep shortages. This could result in over-compensating flexible resources that are capable of helping resolve transient and shallow shortages, and under-compensating resources that contribute to resolving deeper and more serious shortage events.

Therefore, modulating the PPR based on the reserve shortage level would enhance price formation during reserve shortage events and result in more efficient short and long-run decisions from suppliers. In the following subsection, we illustrate one of the negative effects of not providing efficient incentives.

C. Incentives for Energy Storage Resources under Pay-for-Performance

The FCM rules allow battery storage resources to qualify to sell 100 percent of their maximum capability. Owners of energy storage units are exposed to significant performance risk under the PFP framework, however, the current PFP rules do not provide sufficient discipline to energy storage resources in qualifying their capacity for the FCM. Battery storage resources are generally over-compensated for their contribution to system reliability. In this subsection, we discuss this issue further and illustrate the misalignment using simulation results.

Although a storage resource is limited in the duration over which it can provide energy, it can provide reserves for extended periods of time. Unless required to discharge and produce energy during load shedding events, its reserve capability will not be diminished during reserve shortages. Our simulations of a system with just enough capacity to satisfy a 1-day-in-ten-year standard indicate that load shedding is expected to occur in only two percent of reserve shortage hours.[36] Accordingly, the risk of PFP penalties may not be significant for storage resources relative to the potential upside in the form of higher capacity revenue.

Although the owners of storage resources may find it profitable to sell 100 percent of their capacity in the FCM, the reliability value they provide is not likely to be consistent with their compensation. This is illustrated in Figure 12, which shows a hypothetical series of five days with reserve shortages, three of which also show load shedding. Hours with load shedding or reserve shortages are identified with the letter “L” or “R”. Hours are shown as green if the resource would receive credit under the PFP rules and red if the resource would be deemed unavailable. The example is shown for a two-hour resource.

36 The actual simulations were based on the representation of the NYISO system in GE-MARS for 2017/18. While the duration of reserve shortage events and load shedding events are likely to vary from market to market, this analysis captures the essential fact that some load shedding events are longer in duration than the capacity of battery storage resources.

Figure 12: PFP Revenues and Penalties for a 2-Hour Battery During a Reserve Shortage

Hour ➡	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Day 1											R	R	R	R	R	R	R	R						
Day 2											R	R	R	R	L	R	R	R						
Day 3											R	R	R	R	L	L	L	R						
Day 4											R	R	R	L	L	L	L	R						
Day 5											R	R	R	R	R	R	R	R						

Reserve Shortage Hours

R = Reserve Shortage
L = Load Shedding

PFP Penalty
PFP Revenue

The example shows eight load shedding hours and 32 hours with just reserve shortages. On Day 1, Day 2, and Day 5, the energy storage resource is not used for its full duration of two hours, so it has sufficient charge to provide 100 percent of its capacity as energy or reserves in each hour. On Day 3, the unit runs out of charge after hour 16, making it unavailable in hours 17 and 18. On Day 4, the unit runs out of charge after hour 15, making it unavailable in hours 16 to 18.

In this example, the battery storage resource:

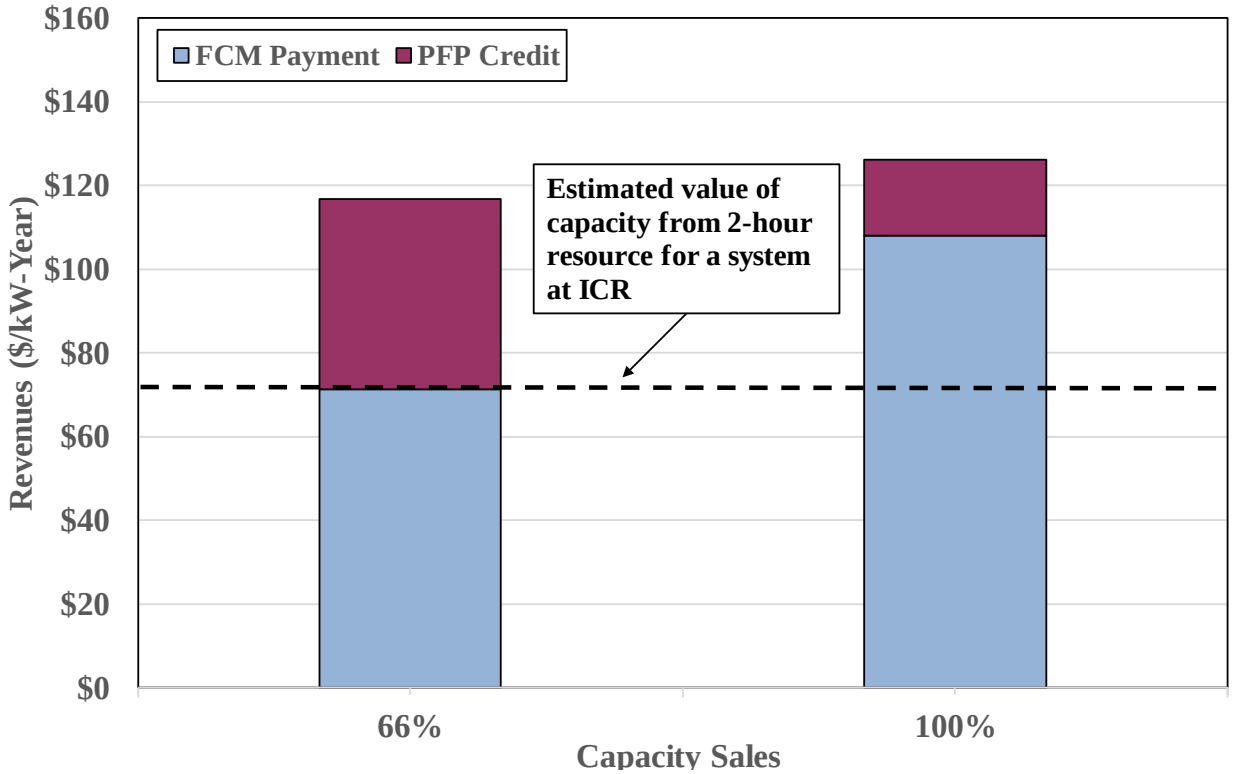
- Has a capacity value of 62.5 percent (compared to perfect availability) because it is helping reduce the magnitude of load shedding in five of eight load shedding hours.
- Will receive a PFP availability rating of 87.5 percent (of perfect availability) because it is providing energy or reserves in 35 of 40 hours with reserve shortages (including load shedding hours).

To evaluate whether there are inconsistencies between the value of battery storage resources for maintaining reliability and the compensation they receive in the capacity market, we performed Monte Carlo simulations of GE-MARS to quantify the value of battery storage resources and the compensation they would receive.[37]

Studies have found that the value of capacity from storage resources is heavily dependent on the penetration level of energy storage resources systemwide. We found that the capacity value of a 2-hour battery storage resource was 63 to 68 percent when the overall penetration of storage resources is 500 MW. In contrast, several 2-hour resources were qualified to sell 100 percent of their maximum capability in FCA-13. We also quantified the number of reserve shortage hours and the combined compensation from capacity revenues and PFP credits for a 2-hour resource would be expected to earn. This is shown for a CSO of 66 percent and 100 percent of its capacity. Figure 13 shows the breakdown of a 2-hour energy storage resource's revenues under these scenarios.

[37] See *Alternative ELR Capacity Value Study: Methodology and Updated Results*, NYISO Installed Capacity Working Group on February 25, 2019 at https://www.nyiso.com/icapwg?meetingDate=2019-02-25.

Figure 13: Breakdown of Revenues for a 2-Hour Battery Resource
Assuming 66/100 Percent Capacity Sales



As shown in Figure 13, storage resources would find it most profitable to sell 100 percent of their capacity in the FCA. In addition, the battery storage resources would also receive more PFP credit than the average capacity supplier. Overall, this resource would receive 117 percent of the compensation of a capacity supplier with average performance.

Even if the storage resources were limited to selling 66 percent of their capacity in the FCA, the battery storage resources would receive a large PFP credit. Overall, this resource would receive 108 percent of the compensation of a capacity supplier with average performance. Although this would reduce the over-compensation to the battery storage resource, it would leave the compensation far above the estimated efficient level of 66 percent.

Hence, the 2-hour battery storage resources appear to be over-valued significantly in the capacity market for two reasons:

- Storage resources are able to sell 100 percent of their maximum capability even though resource adequacy modeling indicates 2-hour storage resources are far less valuable for preventing load shedding than the average conventional resource.
- Storage resources are likely to have high rates of availability during operating reserve shortages and comparatively lower availability during load shedding events.

A key reason why the PFP construct would over-compensate storage resources is that the PPR is the same for all reserve shortages, regardless of the probability that additional reserves would help avoid load shedding. A graduated PPR that rises with the magnitude of the reserve shortage would largely correct the over-compensation to these resources.

D. Conclusions and Recommendations

The Pay-for-Performance ("PFP") rules were put in place to enhance incentives for suppliers to perform when they are needed the most. In this section, we summarize market conditions and settlements during the first PFP event that occurred since the rules became effective on June 1, 2018. We evaluate the efficiency of compensation received by suppliers during the event compared to the risk of not serving load and the value of lost load. We also identify a misalignment between the compensation of short-duration energy limited resources and their value to the system during reserve shortage events.

The first PFP event in New England occurred for two-and-a-half hours on September 3 during which a shortage of 30-minute reserves ranged up to 880 MW. The shortage resulted primarily from unexpectedly high load (actual load exceeded forecast by ~2.5 GW) and the sudden loss of generation (~1.4 GW). In response, the ISO cut exports, made emergency purchases, and activated Price-Responsive Demand. The combination of shortage pricing and PFP incentives led to marginal compensation rates of up to $4700/MWh. Performance of individual resources was generally consistent with expectations as steam turbines accounted for the majority of PFP charges because they had not been economic to commit in the day-ahead market. Every other category of resources received more credits than charges and fast-start units and importers did particularly well.

During reserve shortages, prices should rise gradually with the severity of the shortage, reflecting the marginal reliability value of reserves given the size of the shortage level and potential supply contingencies. The marginal reliability value of reserves is equal to the expected value of the load ("EVOLL") that will not be served if the available reserves are reduced by 1 MW. Assuming a $30,000/MWh value of lost load ("VOLL"), we estimated the probability of contingencies that could result in load shedding during the event on September 3. Furthermore, we extrapolated from these data how quickly the EVOLL would have risen after the occurrence of one or more contingencies.

We estimate that the EVOLL ranged from $700 to $1,000 per MWh of operating reserve during the event, far lower than the marginal rate of compensation which ranged from $3000 to $4700 per MWh. However, we find that for shortages of more than 540 MW, the EVOLL would quickly rise above $4700 per MWh up to the assumed VOLL of $30,000 per MWh. This illustrates the deficiencies with the current PPR, which is set at a single value regardless of the magnitude of the shortage. Modulating the PPR based on the reserve shortage level would

enhance price formation during reserve shortage events and result in more efficient short and long-run decisions from suppliers.

Interest in battery storage and other energy limited resources has grown quickly in recent years as policy-makers look for non-fossil fuel options for integrating intermittent renewables. However, these resources present special challenges for valuing capacity and energy and operating reserves under shortage conditions. We evaluate the reliability value of a 2-hour battery storage resource and find that such units are likely to be greatly over-compensated for their value under the current capacity market rules, including the PFP compensation provisions. This is troubling as policy-makers and developers prepare to invest heavily in this technology in the coming years.

The FCM rules allow battery storage resources to qualify for 100 percent of their maximum capability, but these resources have significant duration limitations that make them less valuable than most conventional resources when the system is near load shedding conditions. Furthermore, the flexibility of these resources make them likely to perform better under the PFP provisions than most resources during mild to moderate reserve shortage conditions. As discussed above, the marginal compensation rate is far higher than the EVOLL during such reserve shortages, leading battery storage resources to be greatly over-compensated.

We performed a Monte Carlo analysis to estimate the reliability value of a 2-hour battery storage resource for avoiding load shedding and the compensation it would receive in the capacity market. This found that a 2-hour battery storage resource would:

- Have 66 percent of the value of an average conventional resource for avoiding load shedding, and
- Maximize profits by selling 100 percent of their capacity in the FCA and earn 18 percent more in PFP credits.

Furthermore, this significant over-compensation cannot be fixed by reducing the qualified capacity to these resources to an appropriate level (e.g., 66 percent) because this would increase the size of the PFP credit for a combined total of 108 percent of the average conventional resource. A key reason why the PFP construct would over-compensate storage resources is that the PPR is the same for all reserve shortages, regardless of the probability that additional reserves would help avoid load shedding. A graduated PPR that rises with the magnitude of the reserve shortage would largely correct the over-compensation to these resources.

VI. APPENDIX

In Section V.B we evaluated the efficiency of prices during reserve shortage events. We compared the actual/ likely prices against the EVOLL at several levels of depleted ten-minute reserves. Our estimated EVOLL reflects an assumed VOLL, and a probability of losing load that we estimated using a Monte Carlo simulation. The simulation incorporates the risk of concurrent generator forced outages to estimate the risk of losing load at each reserve level. The key assumptions and methodology for our simulation are as following:

- We assumed the mix of energy and reserve supply in our simulated system to be similar to the actual mix observed during the September 3, 2018 PFP event. We calculated the average contribution of energy and reserves from each resource duing the PFP event to develop a representative resource mix for our simulation. We scaled down the reserves supplied by each unit uniformly to determine the resource mix at each reserve level.

- For each given reserve level, we performed 10,000 simulations and determined the number of iterations during which load shedding would occur due to generator outages. We assumed that load shedding would occur when the ten-minute reserve levels drop below 700MW. We calculated the probability of losing load for the given reserve level as the fraction of iterations with load shedding.

- For each iteration, we estimated the aggregate generator forced outage as follows. Each generator was assigned a random number between zero and one. If the assigned random number was less than $1\text{-}e^{(-ORP\ /\ MSTUO)}$, the generator was simulated to be forced out of service. For this analysis, we assumed a two-hour outage recovery period (ORP), which is the time needed to fully respond to supply-side contingencies. For each generator, we utilized the NERC GADS database to estimate a class-average Mean Service Time to Unplanned Outage (MSTUO). The class-average MSTUO data we assumed is shown in the table below.

Table 6: Mean Service Time to Unplanned Outage by Generator Type

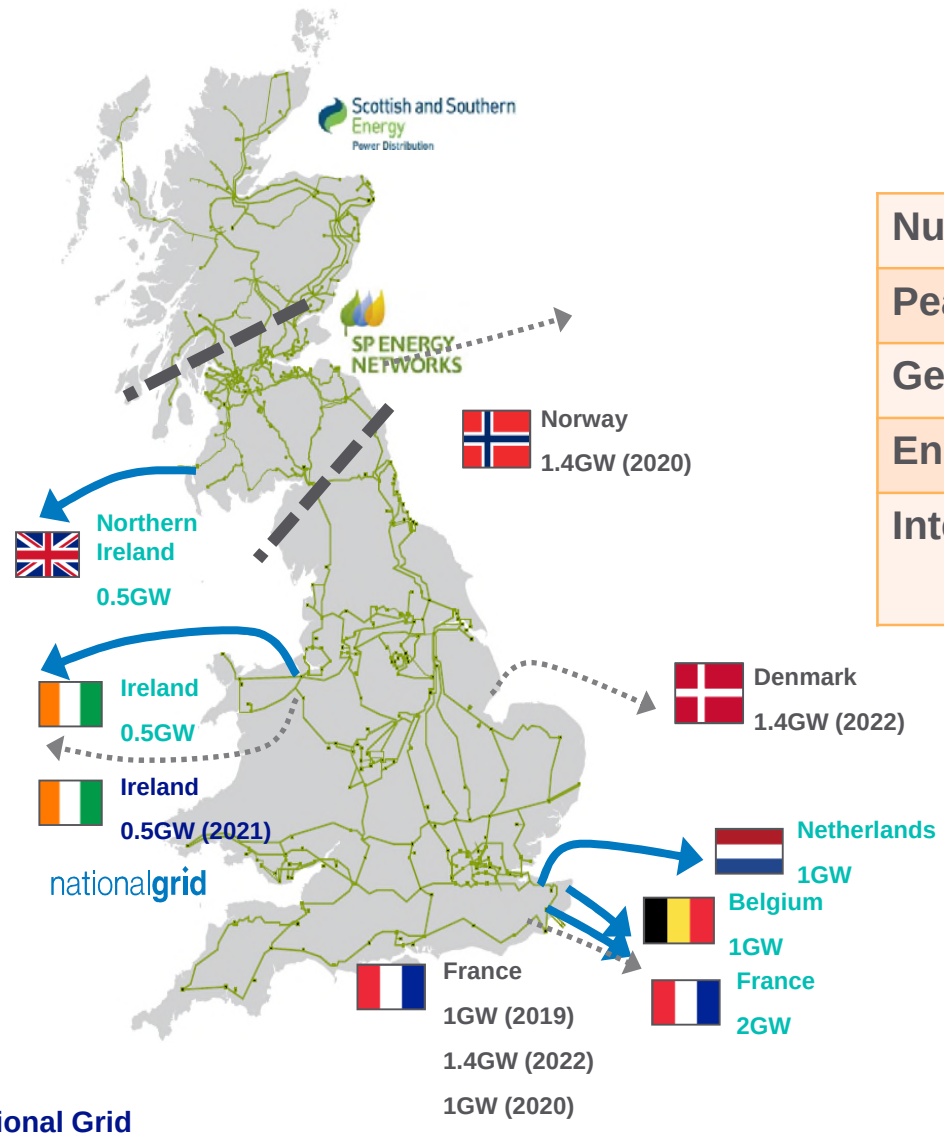
Technology	MSTUO (Hours)
Coal Steam	613
Gas Steam	342
Nuclear	4194
Combustion Turbine	61
Combined Cycle	304
Hydro	459
Others	342

The Changing Energy Landscape – UK Experience

Mike Calviou,
Senior Vice President, Strategy & Regulation
June 26, 2019

nationalgrid

Background to the UK System



Number of customers	30 Million
Peak Demand	55GW
Generation Capacity	80GW
Energy Delivered (2018)	330TWh
Interconnector Capacity (DC)	5GW

The UK energy landscape has been changing

2009

Nuclear	Gas	Coal	Wind	Solar
11GW	30.4GW	23.1GW	4.4GW	-





2019

Nuclear	Gas	Coal	Wind	Solar
9.2GW	32.2GW	11.4GW	21.7GW	13.1GW

Drivers of Change

Decarbonisation

4 times

Increase in all renewable capacity since 2010

Decentralisation

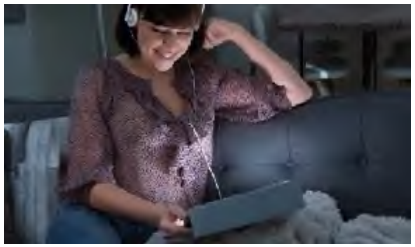
3 times

More distributed capacity connected than in 2010

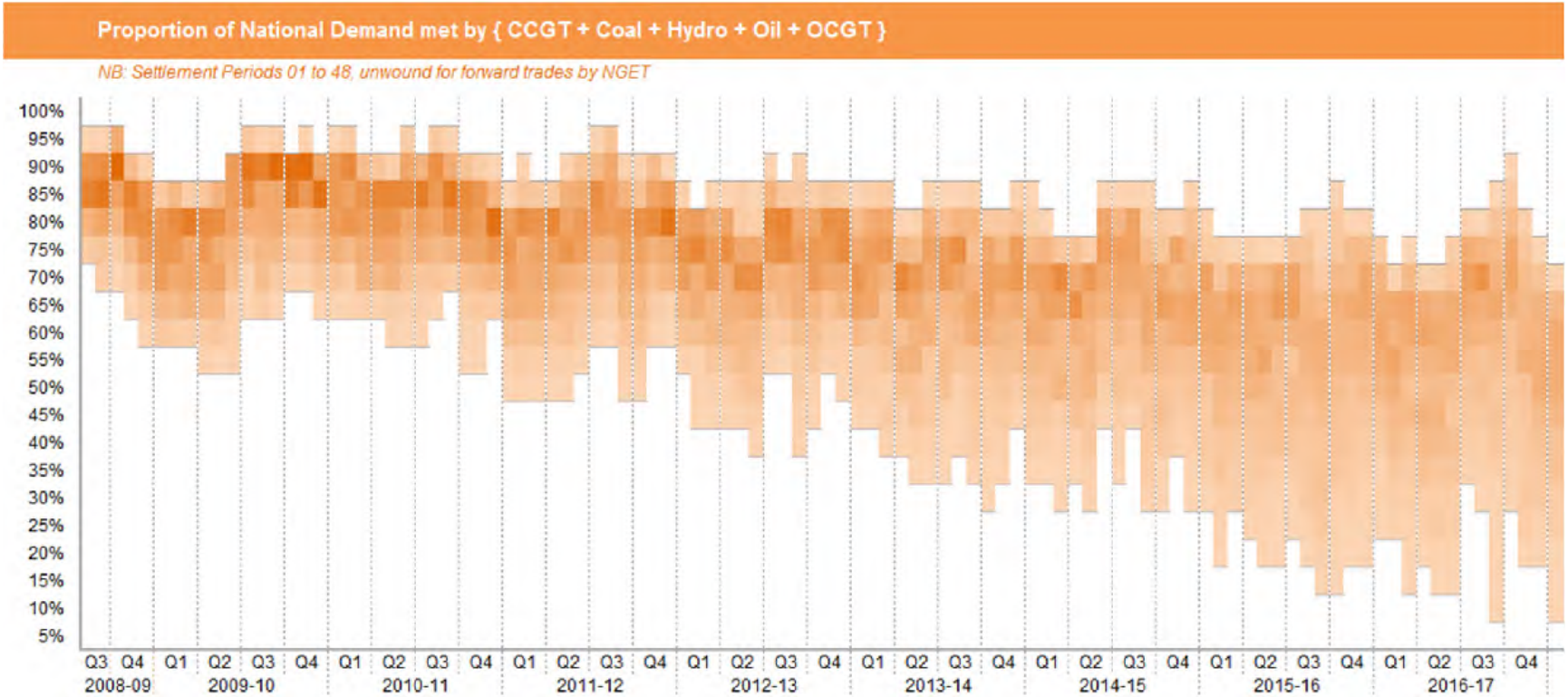
Digitalisation

14.3 M

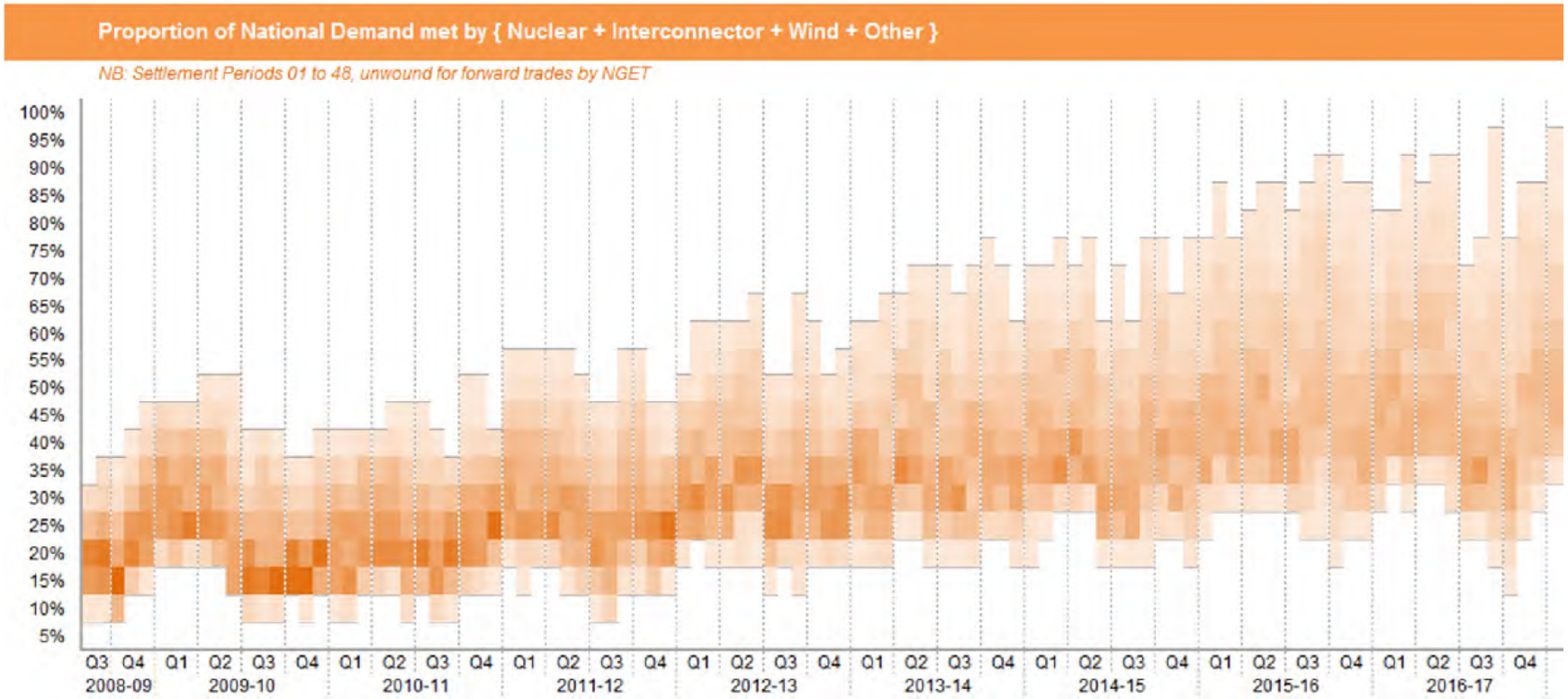
Smart and advanced meters in homes & businesses in GB



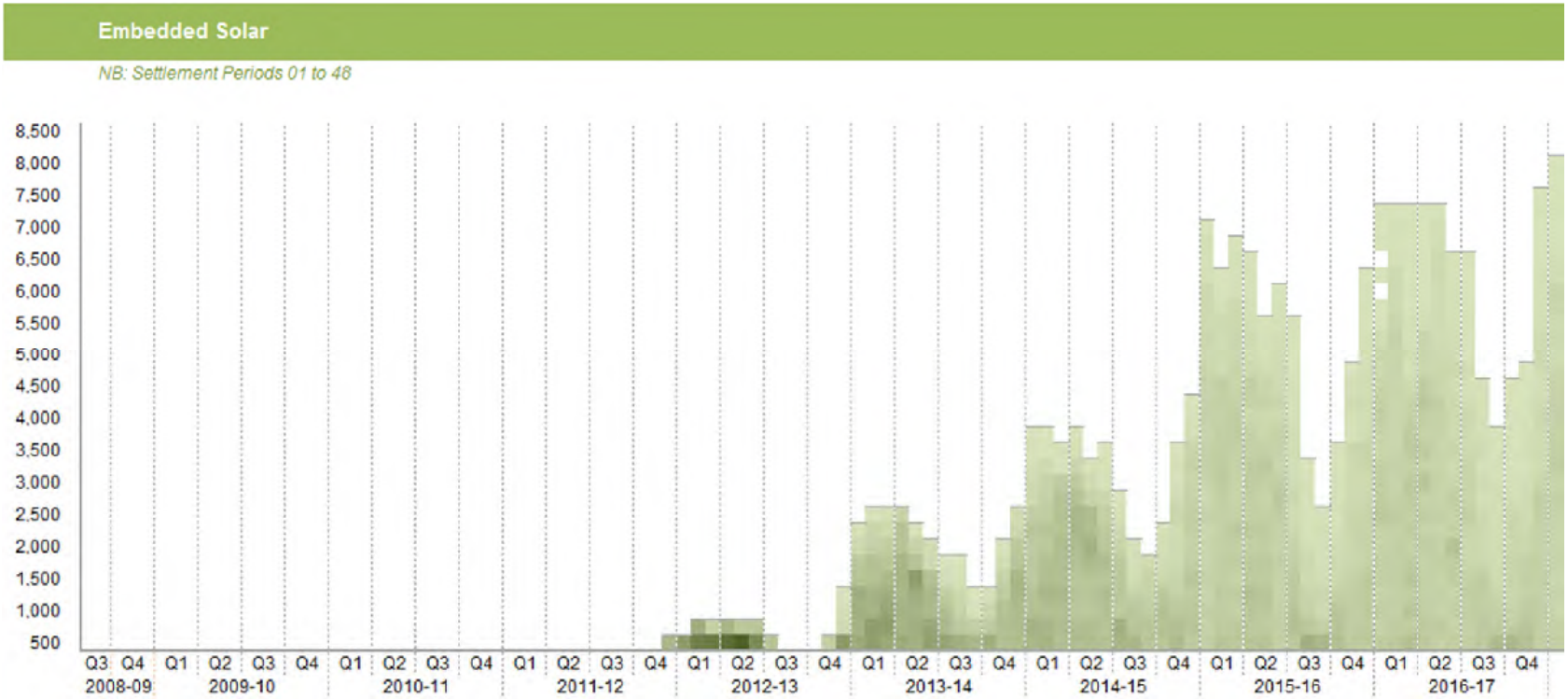
Evolution of the Generation Mix



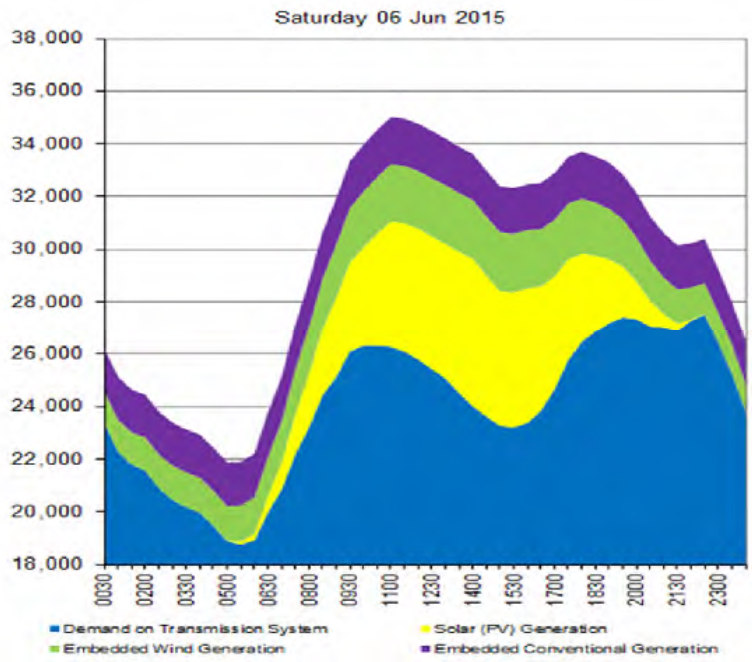
Evolution of the Generation Mix

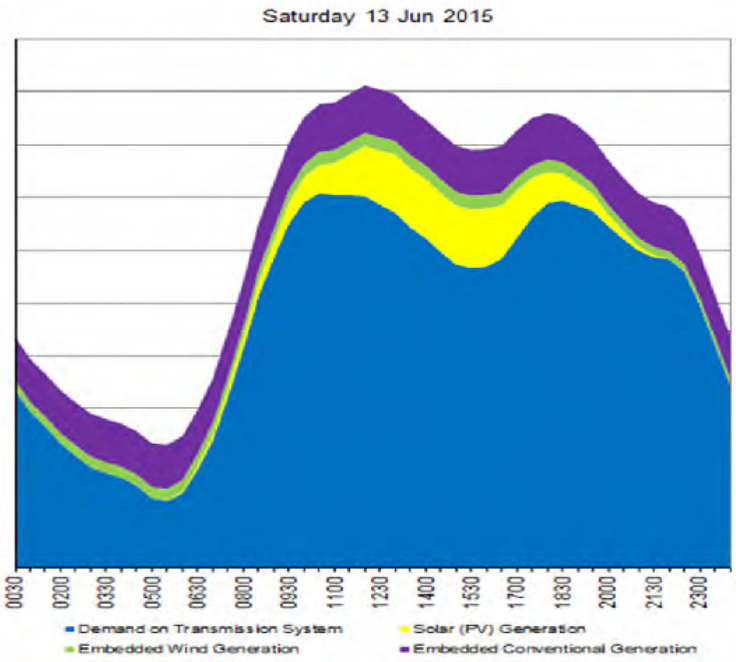


Growth of Embedded Solar



Transmission system demand varies significantly in summer due to solar generation on distribution system





A review of some of the past year's GB system records

13 July 2018

GB passes 1000 hours without coal in 2018

8 February 2019

15.3GW of wind generation

8 May 2019

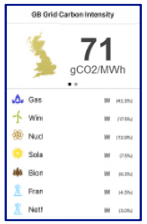
1 week of electricity without coal

31 May 2019

2 weeks of electricity without coal

27 August 2018

Generation hits carbon intensity minimum at 71 gCO_2/MWh



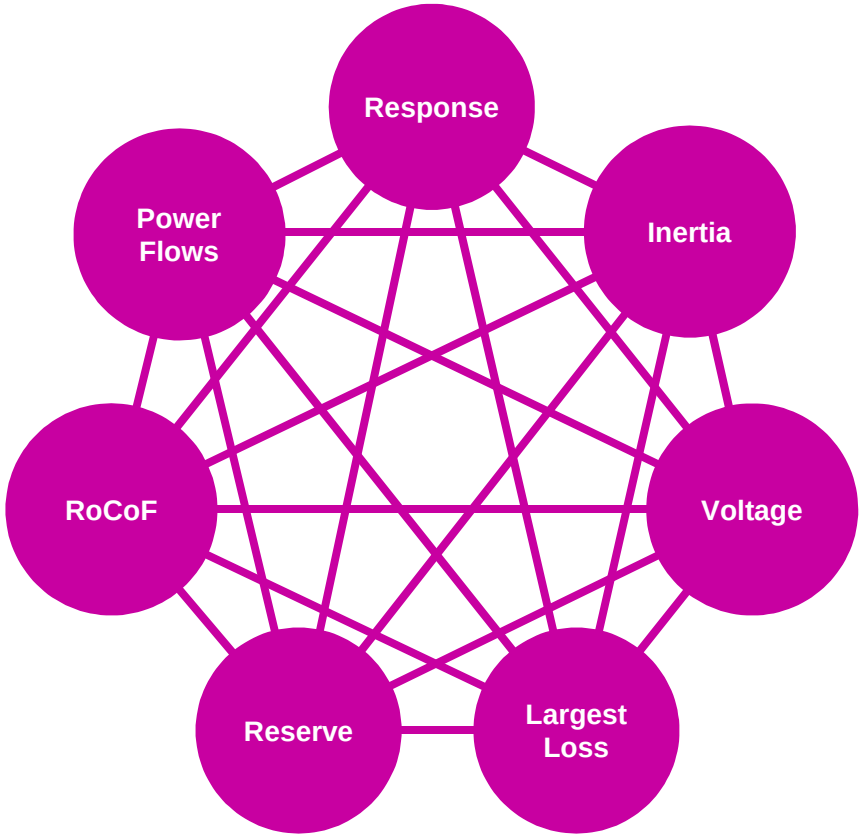
14 May 2019

9.6GW of solar generation

Impact on the transmission system

- More generation connected to distribution system
- Move from small number of large generators to smaller sources
- Uncertainty on system increased
- Dynamics of system changed
- Requirement for more flexibility on the system
- Sources of flexibility have changed

The Daily Juggling Act



On a daily basis we need to manage the system in a safe and economic manner

Many issues to manage which may be conflicting. Sorting out one issue can create other problems

Challenges are increasing due to plant mix:

- Uncertainty on system has increased due to renewables
- Response, reserve and inertia have all traditionally been provided by coal and gas plant
  - In summer and overnight this is often not generating - expensive to bring on as we need to reduce output from low carbon resources
- Having access to flexible assets on the system is key to solving many of the issues economically
  - Focus on encouraging new sources of flexibility

The future is uncertain

Uncertain Demand

3 to 11 million

Electric Vehicles driving on our roads by 2030

Uncertain Supply

37 to 50 GW

Of wind capacity generating on the system by 2030

Uncertain Markets

10s to 1000s

Of active energy suppliers across the country by 2030

Introduction to our Future Energy Scenarios (FES)

Our scenarios outline different credible pathways for the future of energy for the next 30 years and beyond. These consider how much energy we might need and where it could come from. They look at what the changes might mean for the industry, our customers and consumers.

Level of decentralisation

	✗✗ 2050 carbon reduction target is not met	√√ 2050 carbon reduction target is met
	Consumer Evolution	**Community Renewables**
Electricity demand	Moderate-high demand: high for electric vehicles (EVs) and moderate efficiency gains	Highest demand: high for EVs, high for heating and good efficiency gains
Transport	Most cars are EVs by 2040; some gas used in commercial vehicles	Most cars are EVs by 2033; greatest use of gas in commercial vehicles but superseded from mid 2040s by hydrogen (from electrolysis)
Heat	Gas boilers dominate; moderate levels of thermal efficiency	Heat pumps dominate; high levels of thermal efficiency
Electricity supply	Small scale renewables and gas; small modular reactors from 2030s	Highest solar and onshore wind
Gas supply	Highest shale gas, developing strongly from 2020s	Highest green gas development from 2030s
	Steady Progression	**Two Degrees**
Electricity demand	Moderate-high demand: high for EVs and moderate efficiency gains	Lowest demand: high for EVs, low for heating and good efficiency gains
Transport	Most cars are EVs by 2040; some gas used in commercial vehicles	Most cars are EVs by 2033; high level of gas used for commercial vehicles but superseded from mid 2040s by hydrogen
Heat	Gas boilers dominate; moderate levels of thermal efficiency	Hydrogen from steam methane reforming from 2030s, and some district heat; high levels of thermal efficiency
Electricity supply	Offshore wind, nuclear and gas; carbon capture utilisation and storage (CCUS) gas generation from late 2030s	Offshore wind, nuclear, large scale storage and interconnectors; CCUS gas generation from 2030
Gas supply	UK Continental Shelf still producing in 2050; some shale gas	Some green gas, incl. biomethane and BioSNG; highest import dependency

Speed of decarbonisation

We engage stakeholders throughout the year to build and publish the FES

331 stakeholders, from 242 organisations.
Live streamed to 173 stakeholders

65 conferences, workshops and other industry events

119 stakeholders attended 5 webinars

62 organisations involved (26 new organisations included)

- 419 queries answered
- 6 editions of newsletter sent to 7000+ subscribers
- Nearly 70,000 website views

- Call for evidence – 70 organisations
- Workshops - 2 general and 2 specific Scottish / Welsh Government and two themed. 189 stakeholders/128 organisations

Our FES inform a whole suite of recurring documents

Figure 1.1
National Grid System Operator publications

Future Energy Scenarios (July)
A range of credible pathways for the future of energy from today to 2050. Scenarios are unconstrained by network issues.

The ETYS, GTYS take the unconstrained scenarios in *FES* to develop scenarios in *FES* to develop requirements for planning and operating the electricity and gas transmission system over the next 10 years.

Needs case

Electricity Ten Year Statement
November
The likely future transmission requirements on the electricity system.

Gas Ten Year Statement
November
How we will plan and operate the gas network, with a ten-year view.

Options

Network Options Assessment
January
The options available to meet reinforcement requirements on the electricity system.

Ten Year Network Development Plan
Overview of the European gas and electricity infrastructure and its future developments.

The operability publications consider the unconstrained scenarios in *FES* to explore operability risks and associated requirements of the transmission networks and services.

System Operability Framework
How the changing energy landscape will impact the operability of the electricity system.

Gas Future Operability Planning
November/ December
How the changing energy landscape will impact the operability of the gas system.

Ad-hoc, insights -led productions and reports

Same link supplied for GFOP and FGSP – need new cover and link for FGSP

Operability Strategy report
Highlights the challenges we face in maintaining an operable electricity system, and summarises the work we are undertaking to ensure we meet those challenges.

Future gas supply patterns
How variability in supply pattern seasonally and day-to-day has changed, and could change in the future.

We also produce ad-hoc reports that develop shorter term plans for more specific elements of the operational assets and services, where the need arises.

Capacity report
Capacity Market auctions for delivery in 2019/20 and 2022/23

System Needs and Product Strategy
Our view of future electricity system needs and potential improvements to balancing services markets.

Product Roadmap for Restoration
Our plan to develop restoration products.

Wider Access to the Balancing Mechanism Roadmap
Our plan to widen access to the balancing mechanism.

Product Roadmap for Reactive Power
Our plan to develop reactive power products.

Transmission Thermal Constraints Management
Our plan for the management of thermal constraints.

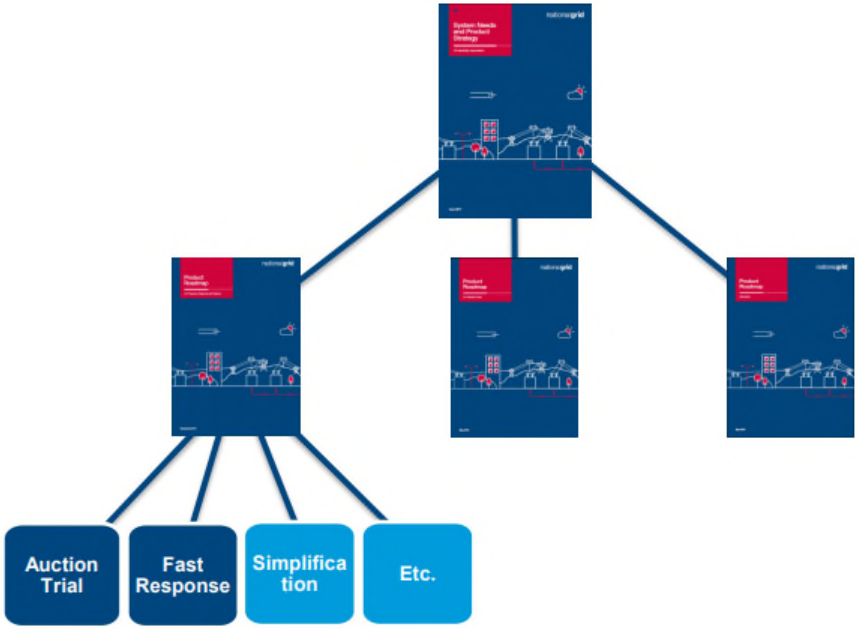
Each year we provide short-term forecasts that explore any operational challenges anticipated over the summer and winter periods.

Winter Review and Consultation
June
A review of last winter's forecasts versus actuals and an opportunity to share your views on the winter ahead.

Summer Outlook Report
April
Our view of the gas and electricity systems for the summer ahead.

Winter Outlook Report
October
Our view of the gas and electricity systems for the winter ahead.

Based on our System Operability Framework, we published SNaPS and the corresponding product roadmaps



System Needs & Product Strategy	Published in Jun. 2017
Product Roadmaps and Reports	First Product Roadmap published in Dec. 2017
Specific Developments	Included in the Forward Plan

Dedicated Programmes Encourage Innovation

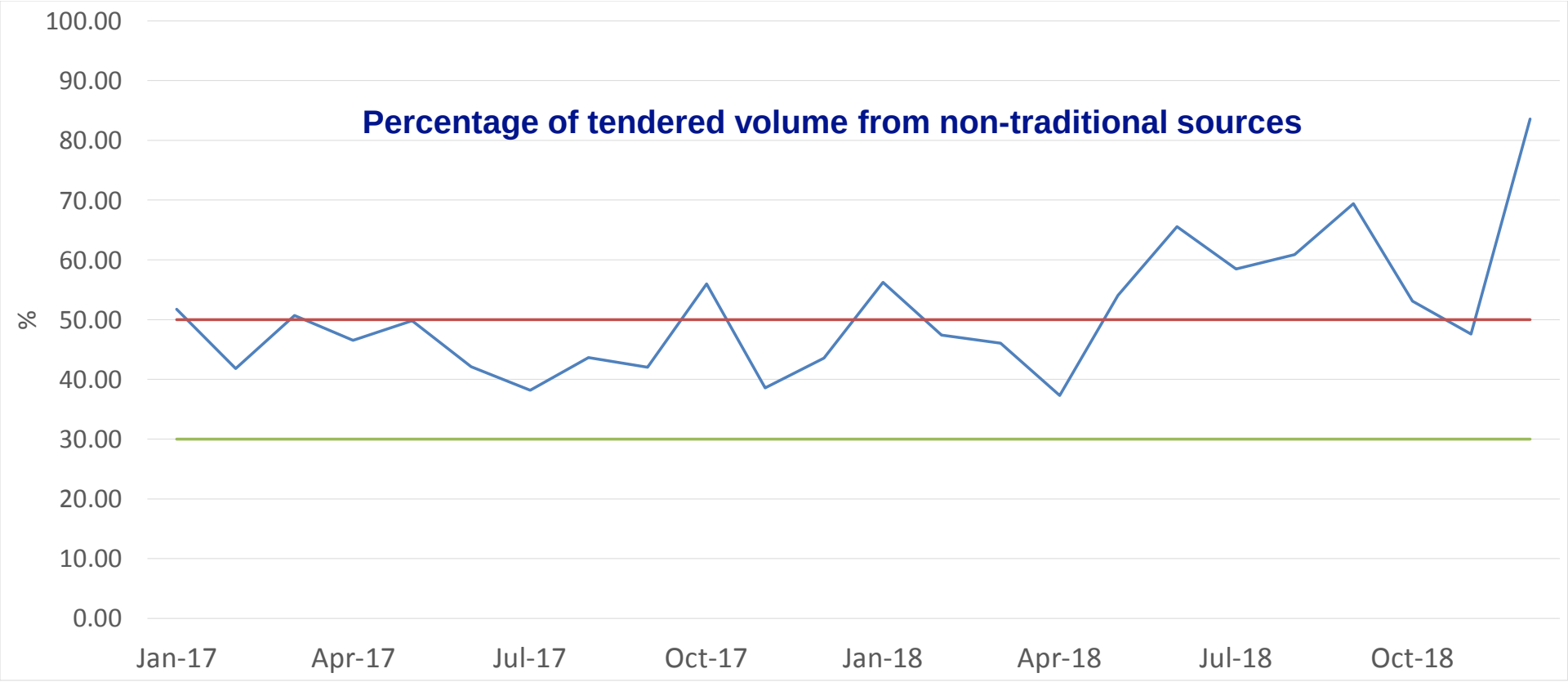
power responsive

1	Customer Engagement: Raising Awareness & Clarity
2	Increasing Confidence in Flexibility
3	Evolution of Flexibility Markets

- **~2500 stakeholders** on the Power Responsive stakeholders list
- **100% increase in new distribution connect units** in 2018

http://f1.media.brightcove.com/4/867903724001/867903724001_5136648725001_5136643375001.mp4?pubId=867903724001&videoId=5136643375001

Power Responsive has successfully stimulated new sources of flexibility



We work more and more collaboratively with our stakeholders to understand the future needs of the system

ESO forums

Industry-led forums

RIIO-2 stakeholder engagement process

Our most recent strategy publications

Towards 2030: A System Operator for GB's Energy Future

19/21 Forward Plan

RIIO-2 Ambition

Innovation Strategy

Some UK Lessons

Change

- There has been a lot of change and it will continue
- It happens quicker than you think it will
- Scenario planning is essential

Whole System Thinking

- Energy systems are becoming more complex and interdependent
- Closer links between DNOs and ESO due to growth in distributed generation
- Closer links between gas and electricity due to more intermittent running of CCGTs

ESO has Key Role in Facilitating Change

- Removing barriers to entry in existing markets for new resources
- Developing new markets for operability to provide commercial solutions to technical challenges, (e.g., demand turn up)
- Increased working with DNOs to facilitate more connection of distributed generation

This is an opportunity if you embrace it

- ESO has key role in providing strong thought leadership on how to transition to low carbon world
- DNOs will see a major transition as they move towards active management of their networks and drive solutions through markets
- Innovation is key in creating of new markets and development of technical solutions

Lessons for New England?

Some observations

The region recognizes the challenges, opportunities and uncertainties of the changing energy landscape.

Rapid regional growth in renewables and distributed generation is leading to greater complexity in the operation of the network and the design of the markets.

The ISO is re-focusing and its role evolving to support the transition to the low emissions future.

The changing landscape is, to a surprising degree, comparable to that faced in the UK.

Going forward

The system operator is well-placed to become the thought-leader through the change.

Proactive scenario planning is an effective tool for exploring policy options and informing decision-making.

Further market design / development will also be essential to accommodating the needs and potentials of new technologies and in delivering their benefits to Customers.

Electrification of Transport and Heat is also on the horizon. It will require further optimizing the existing network as it will be the backbone of that transition.

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HARVARD LAW SCHOOL | ENVIRONMENTAL & ENERGY LAW PROGRAM

Ari Peskoe's Remarks at NEPOOL Participants Committee Meeting

Newport, Rhode Island – June 26, 2019

For historical reasons, environmental regulation is often considered separately from the legal frameworks that specifically govern the electricity industry. But that sort of line drawing has been out-of-date for some time, particularly in New England. In an alternate universe, I'm here today talking about implementing the Clean Power Plan, which was criticized for going too far in acknowledging the blurred lines between environmental and power sector regulation.

New England states have long been leaders on this front. No coal plant has opened in the region since November 1989, when a 214 MW plant in New London opened. Before that, I can't find any coal plants opening since 1968.

Last week, the Rhode Island site board rejected an application filed by Invenergy to construct a new combined cycle plant. Opposition to natural gas infrastructure is not new, as pipeline developers understand. I wonder if the region's last large-scale natural gas plant has already been sited. For that matter, will the region site any new fossil fuel infrastructure? The fuel security debate reflects that the ISO has apparently accepted this reality and is attempting to work around the constraint.

As far as I have seen, the ISO has not yet fully embraced the fact that the states are only interested in entry of zero emission or storage resources. In the near-term, new entry mandated by states is incompatible with the market paradigm – as we all know, over the next ten years, gigawatts of offshore and onshore wind and new hydro from Canada will likely come online. By the time the ISO-run energy market turns 30, about half of the region's electric energy will be generated by resources that entered the market through state-mandated long-term contracts.

The issue that I'd like to address today, is the future of markets after this round of utility procurements. The states want a low-carbon power system, and they're going to get one. I can't overemphasize that point. I think most people here understand that point, but the reality is that that the market design does not reflect it. The question is whether the ISO-administered markets will be the vehicle for building our 21st century low-carbon power system.

This carbon challenge will be the third major task that this group has taken on. Regionalization was the first challenge. Restructuring was the second. In the 2020s, NEPOOL has an opportunity to lead on a regional carbon solution. To continue the with R-words, I'll call this third task – Reduction, and I'm open to suggestions.

Before I speculate on the future, I'll start at the beginning.

I dusted off the September 21, 1972 FPC order approving the NEPOOL agreement. In that order, the Federal Power Commission summarized:

The stated goals of NEPOOL are to attain for New England the maximum practical economy consistent with proper standards of reliability, in the generation and transmission of bulk power through joint planning, central dispatching, coordinated operation and maintenance of the

generation and transmission facilities. These goals also include equitable sharing of resulting benefits and costs. NEPOOL Power Pool Agreement, 1972, 48 FPC 538

Joint planning, central dispatch, coordinated operation and maintenance to achieve maximum practical economy and reliability, all with equitable sharing of costs and benefits.

Kudos to your predecessors for crafting a set of goals that has endured. Regional coordination in order to achieve maximum *practical* economy and reliability, while equitably sharing costs and benefits among utilities.

To show you how well these 1971 goals have endured, consider the current NEPOOL mission statement. The organization's website has a lengthy articulation of the mission for the market and transmission arrangements, but I prefer the succinct Mission Statement at the back of the Annual Report.

It says: "NEPool's mission is to create and sustain open, non-discriminatory, competitive, unbundled markets for energy, capacity, and ancillary services that are balanced between buyers and sellers."

Unbundled markets are now the vehicle for regional coordination to attain maximum practical economy. And equitable sharing of costs and benefits evolved into balance between buyers and sellers, to reflect the transition from vertically integrated utilities to today's market.

On this last point – The New England region is the only regional market that has so extensively achieved that balance by separating buyers from sellers. MISO and SPP are both dominated by vertically integrated utilities, and about half of generation in PJM is owned by utility holding companies with distribution utilities in the footprint or vertically integrated utilities. Regional power markets are good, and they're even better when buyers don't like high prices. Even without real-time retail prices, New England states could do more to incentivize utilities to reduce their wholesale purchasing costs. Then we'd have a market of rational buyers and sellers.

What we have instead is a regional platform for competition among supply-side resources. Since 2003, locational marginal prices have been the mechanism for facilitating open and non-discriminatory competition. LMP has since been supplemented with various products and markets, with more changes on the way.

LMP is a means for aligning operations with incentives to approximate least-cost dispatch. As we think about what the market should be achieving in the late 2020s, we should consider how to do as much as possible within a framework that maintains this underlying connection between economics and energy flows. But fidelity to NEPOOL's mission is, I think, the ultimate benchmark. Each new product, market, or procurement should advance regional coordination that is balanced between buyers and sellers.

Returning to my 2020s hypothetical, imagine that the state procurements enshrined in law today have been realized. In my future, this would mark the end of phase 2 of decarbonizing the regional power system. Phase 1 began when the markets opened – 20 years ago last month. CO2 emissions today are about a third lower than 1999, and that decrease is due in large part to natural gas displacing coal and oil in the wholesale market. For the most part, we've reached the end of the line with these carbon reductions. It may be possible to squeeze limited additional carbon reductions from the current LMP + FCM framework. But absent changes and interventions, this framework

would likely increase CO2 emissions, as retiring nuclear plants would be replaced in part by natural gas.

So states pursued phase 2 – large-scale procurements of resources with high capacity factors – because the market design did not present an alternative for decarbonization. To the extent that phase 2 threatens the regional coordination gains of phase 1, I think it's possible to limit the damage.

Phase 3 – starting after these procurements come online - is where decarbonization gets much more challenging. At some point, states are going to have tackle emissions from other sectors, particularly transportation and heat. That will presumably spill over to the electric sector.

The policy framework for Phase 3 is just starting to take shape. The parameters are set by states' long-term carbon goals. Five New England states have targets that roughly speaking require 80 percent reductions by 2050. Again – this is happening and no one has a plan for it yet.

In 2016, Massachusetts highest court ordered state regulators to promulgate regulations that will actually achieve the state's carbon-reduction target. NEPGA challenged the state's cap-and-trade regulation in state court, arguing in part that the regulation is illegal because the single-state cap-and-trade will lead to higher regional emissions. The court sided with the state, and Massachusetts' cap and trade is in effect.

If market participants and states are unable to agree on a regional mechanism for achieving decarbonization goals, phase 3 might be characterized by a combination of state procurements and escalating RPS or CES requirements – largely a continuation of phase 2 – combined with inconsistent regulation of CO2 emissions from the region's fossil generators. This hypothetical Phase 3 would threaten the key principles of openness and non-discrimination and mark a major step backward in the decades-long effort to improve regional coordination. Meanwhile, the ISO-NE markets won't drive investment, and RMR agreements may be needed to keep existing assets operational.

To avoid this outcome, the region needs a market-mechanism that will facilitate new entry of low-emission resources. Without an alternative, states will continue down the paths their already on.

In Phase 1, new emission-reducing natural gas plants entered largely through the LMP + FCM framework. Switching from coal and oil steam turbines to natural gas combined cycle plants was consistent with existing physical operations and market dynamics.

In Phase 2, new entry is not based on market expectations but on long-term PPAs that are necessary because LMP + FCM don't provide an entry path for these resources. State-mandated RFPs are, nonetheless, a market mechanism. Like some ISO product markets, an RFP facilitates competition among suppliers while dictating to buyers the products they must to buy. But the RFPs isolate the state from the region, and therefore mark a departure from the decade-long regionalization trend.

States haven't yet mandated long-term contracts in Phase 3, but we know that additional zero or very low emission resources are needed to meet decarbonization and RPS goals.

A regional carbon price was an unattractive option in Phase 2 in part because it doesn't facilitate the new entry that utilities must pay for. I think it's worth reexamining whether a carbon price can play some role in Phase 3.

The purpose of a carbon price would be to improve the market by facilitating entry of resources that utilities must otherwise support, reducing the value of out-of-market energy credits, and enabling cost-effective achievement of state emissions targets, that again market participants must achieve.

Because a carbon fee should be rooted in market improvement and not environmental protection, the amount of the adder should be tied to the goals that the market is trying to achieve. For example, if the fee is aimed at facilitating compliance with 80% by 2050 targets, then the amount should be aimed at achieving that result. There is no reason to tether a regional carbon fee to the social cost of carbon.

Opponents of a carbon adder will undoubtedly argue that it's illegal, beyond FERC's authority to approve. Without getting deep into the legal weeds, I think that carbon price opponents leave the ISO and FERC in an awkward position.

It would be a very odd result if FERC is prohibited in its market oversight from accounting for one of the major drivers of power-sector investment in the region, and if FERC's only move, as a matter of law, is to erect barriers to market participation in order to protect resources that buyers don't want. FERC's mandate under federal law to ensure that wholesale rates are just and reasonable is a delegation of authority that by its nature conveys broad discretion to the Commission to regulate transactions under its jurisdiction. It would be a perverse outcome if FERC's discretion was constrained by labelling a regulation "environmental," and thereby prohibiting FERC from incorporating it into a just and reasonable rate.

A carbon price would open opportunities for interregional collaboration. Quebec has an economy wide cap and trade that is linked to California's program. New York enacted major carbon reduction legislation last week. Of course, New York and New England already collaborate through RGGI, which could obviate an ISO-administered carbon fee if the cap were significantly ratcheted down.

If a fee on carbon emissions is not politically viable, perhaps payments for reducing carbon emissions may be more attractive. Conservation Law Foundation and others introduced a proposal during IMAPP that would do just that. The proposal would pay resources for emissions reductions, which is exactly what the region needs.

If carbon-based prices or payments are not possible, a sub-optimal solution that might not fit neatly within the LMP framework is better than the alternative of more utility-mandates and inconsistent state CO2 emission regulations. At the end of the day, NEPOOL's guiding principles should govern -- regional coordination is the ultimate goal. If there is no regional alternative, states will continue down the path they are on with more utility mandates. To repeat myself – the regional power sector is going to decarbonize. The question is what role will the regional market play in enabling that transition.

If the market design issue is intractable and you're resigned to state-specific procurements forever, then the markets can be explicit about that outcome. The region must also retain resources needed for reliability. The regional capacity construct was ostensibly intended to meet this goal, but it is now disconnected from resource adequacy and reliability. The region doesn't need a capacity construct that is designed to procure fungible megawatts.

What sort of financing mechanisms can withstand volatile energy prices that might accompany a region with high penetrations of low marginal cost resources? Will those financing mechanisms be

overseen by the ISO, or will market participants and financial institutions develop them without any new FERC-regulated products?

I also wonder if there is a regional solution to long-duration storage. As offshore wind comes online, there will be excess renewable energy generation in the spring and fall. Perhaps investors can develop a business models for storing that energy – but will any investor be willing to shoulder the risk of investments premised on seasonal arbitrage?

One more thing in the 1972 FPC order that I think is relevant -

"The participants to the Agreement have subordinated some of their own self-interest objectives in order to achieve a workable pooling arrangement for their own benefit and for the benefit of the whole geographical area involved."

Will states be satisfied with a regional solution, if a credible proposal is presented, or will they continue to want to pick their resources? Can they subordinate some of their own self-interest? RPS laws and RGGI, both of which preceded the current procurements, were regional solutions, so there's reason to be optimistic.

But what about the companies represented here? I think leadership needs to come from the long-term market participants – the ones who intend on being here and will be here 10, 20, 30 years from now.

We're at a moment of opportunity that will slip away quickly if states pass additional procurement mandates. The easy option is to blame the politicians, who hold all of the cards and can dissolve this 50-year experiment in regionalization. New England has a unique cohesiveness that other markets lack, that might allow it to overcome inertia and provide a path forward for a regional, low-carbon power system.

Opening Remarks: Evolving Markets and Public Policy in New England

Travis Kavulla, Director of Energy and Environmental Policy, R Street Institute

The following is adapted from a speech given at a general session of the New England Power Pool's (NEPOOL) Summer Meeting in Newport, Rhode Island, on June 26, 2019.

It is a delight to be back before NEPOOL, albeit in a windowless conference room that has all the humidity of the littoral climate with none of the maritime viewshed. The last I spoke to NEPOOL, it was at a meeting of your Participants Committee in March 2016. I wisely consulted my notes of that meeting to make sure I had not made any embarrassing predictions. And because I was then a regulator, I am happy to say that I hedged virtually all my bets. But I made at least one prediction, which is that "vague and indirect environmental objectives" likely would drive state policymakers to continue a regime of long-term supply procurements, rather than rely on a marketplace that must have a clearly defined variable to solve for before it can work toward a cost-minimizing solution. Familiar, no?

Integrated Resource Planning: Do you really want to go there?

I spent a lot of time as a regulator in a region, the Western United States, mostly dominated by either utility-owned projects, held in their regulated "rate base," or long-term power purchase agreements. The most frequently asked question in that region seems to be: What led regulated utilities and their regulators to do the crazy stuff 5, 10 or 15 years ago that we are still living with today?

The circumstances in which this question might be asked are various. Some of them relate to coal, some to natural gas and some to clean energy. But when you are making bets about the long-term fortunes of the power sector, sorrow is too often the result, especially when those making the bets—regulators and regulated utilities—are largely insulated from the financial consequences of betting wrongly. Let me review some pertinent examples that come to mind from my own experience.

There was the coal plant in Montana bought in 2008, after a regulated utility said that recent improvements to the turbine-generator unit made the plant "better than new." The decision to put consumers on the hook for it was ushered along by labor unions and local community support, and regulators—indeed, Democratic regulators—approved it. Specifically, the utility regulators signed off on a 35-year depreciation lifespan and a payment of approximately $400 million for 222 megawatts. This would today strike anyone as an astronomical sum to pay for such a facility, especially in light of its remediation liabilities, which were inherited by the new owner. Yet it seemed

competitive at the time, based on the market price forecast, which, everyone seemed to assume, would only continue to escalate.

Then there was the 400-megawatt California simple-cycle gas plant put under contract to Pacific Gas & Electric in the mid-to-late 2000s. Its long-term contract allowed no more than 365 starts per year. Because why would anyone conceivably need to cycle a gas plant more often than once a day? If anyone foresaw what we witness today, where California has an almost twice-daily need for the cycling of gas plants such as these, they did not act on it—not even only a decade ago, when renewables were beginning to be part of the discussion.

Then there was the generation of wind and solar power purchase agreements that baked in renewable prices at 10, 15 or 20 cents per kilowatt-hour. Wind PPAs are now going for 3-5 cents per kwh in the region. These 20- or 25-year contracts have no premium for delivery at higher-value hours, even though renewables are so oversupplied in certain hours that they have driven prices into the negative. No contractual provision exists for the “regulation down” services that renewables can provide when they offer the reliability service of ramping down in response to overproduction of resources or overforecasting of customer demand.

And of course, if we were to venture outside of my home region, and go to the opposite end of the country, we could talk about the heroic assumptions that led state utility regulators not just to approve a new generation of nuclear power plants, but to allow consumers to be charged for the plants before they generated a single kilowatt-hour of juice. So confident that the regulator had selected the right product for Georgians, the chairman of the state’s public service commission said in 2009 that charging ratepayers in advance for “construction work in progress will save customers money and better ensure that the creditworthiness of the Company can withstand the financing of these costs, which again saves money.”

The common thread of all of these examples is that state policymakers decided to act paternalistically—standing in for consumers, sometimes tacitly and sometimes overtly accepting the view that a monopsony was the natural and only vehicle to ensure the policy goals of reliability, affordability and occasionally environmentalism were met. They often used sophisticated systems models to convince themselves of the propositions put to them. This “integrated resource planning,” as it is called by the vertically integrated monopolies that rely on it, was and remains a useful exercise—but it has one enormous blind spot: It does not ask the businesses for whom these investments in generation are accretive to own the risk of the bets that such planning results in.

These decisions were often rationalized in a manner I find deeply ironic: that, somehow, in deciding to hold customers captive to long-term supply arrangements, these policymakers were actually *diminishing* risk to consumers. In fact, these regulators were shifting risk to these consumers.

As New England pivots grandly to the same mold of long-term, government-led commitments, it is worth being aware of at least three, related failures of this mode of regulation:

1. This type of regulation has empirically failed to deliver economic results compared to a marketplace that has many buyers and many sellers. From 2008 to 2016, prices in monopoly jurisdictions have increased relative to prices in restructured jurisdictions. This divergence is not trivial, and on average across sectors surpasses 20 percent.

2. Additionally, these long-term supply arrangements have caused large parts of the country either to miss out on innovations that would disrupt and displace inefficient technologies, or to cause consumers to have to simultaneously pay off the balance of an existing plant even while paying for a new, efficient plant.

3. These arrangements have also meant that in renewable-heavy states, such as California, a power fleet built pursuant to contract terms and regulatory structures that were widespread 10 years ago is affecting the ability to integrate more renewables today.

Climate Change and the Power Markets

I agree with my fellow panelist Ari Peskoe [Director, Harvard Law School, Electricity Law Initiative]: We don't have these power markets for their own sake. They are a means to an end. And the New England states have appeared to declare in policy that they will not countenance any large carbon footprint, at least not in the power sector.

Ultimately, these markets have solved for the public policy demands of affordability and reliability better than regulatory fiat has. Where markets have fallen short in this regard, it is often because of aspects within the markets that resemble the paternalistic elements of regulation. Conversely, where utility regulation has shown bright spots, it tends to be where it has borrowed from the markets: making the utilities have skin in the game, requiring competitive solicitations for power purchase agreements and co-optimizing their generation portfolios in the short run through security-constrained economic dispatch.

And this leads me to my other point of agreement with Ari: The power markets are not solving for, and were not designed for, the accomplishment of environmental objectives. It has been a happy accident that they have resulted in positive environmental outcomes. Many resources that emit no carbon just happen to have small operating

costs, and the selection of power resources by a real-time or day-ahead electricity marketplace is based on the economic merit of offers that are made based primarily on these operating costs. Likewise, markets have allowed more economic, cleaner natural gas to replace less efficient and less clean coal. But there is no objective function to the markets to solve for the variable of carbon-dioxide emissions.

As a technical matter, it would be straightforward enough to have just such a market. It is really policymakers' failure to ask markets to accomplish their ostensible objective that has led politics to take different tangents that are often purposefully evocative of command regulation, such as the "Green New Deal." Yet it must always be said in forums such as these that power markets can and would solve for carbon policy, just as they do for other policy objectives. A price on emissions or a cost for an allowance to emit carbon are both highly compatible with the marginal-cost-based offers that power generators make in the wholesale markets.

Unfortunately, in what has taken on a feeling of a self-fulfilling prophecy, it is said—and it may well be true—that while our politics demands action on carbon, it lacks the political will to actually take aim at its political target. The price on carbon that would be required to accomplish the Paris Treaty climate goals, some say, is too high to be politically acceptable. That, they say, means we must fall back to the third-best option or something even worse, because the most economically efficient manner of regulating carbon emissions—both of which directly price it—are politically unpalatable.

Let us pause to contemplate briefly what that assertion really means. That the approach that would seek out the least-costly carbon emissions reductions is too transparently costly to pursue can only have one implication: The people who want to do something about climate, but who criticize a carbon tax as a vehicle to doing so, are really arguing in favor of hiding the price of these carbon reductions by incorporating them into indirect policies, both raising the overall cost of decarbonization and bamboozling voters in the process.

We sacrifice much when we leap swiftly to a third-best option, such as one that focuses on the procurement of cleaner power plants that will tend to reduce emissions from other power plants. First and foremost, we give up the idea that emissions might be traded off between sectors and technologies that can move between sectors. We essentially concede that we will make the power sector and its customers pay for decarbonization, increasing prices on the very sector whose cost-competitiveness is probably necessary to effect a fuller decarbonization, for example transportation.

Can We Even Have Third-Best Solutions?

Now that I've said the cursory things about how states should actually aim at the target they are trying to hit, I suppose it behooves me to address the reality of this situation, which represents a kind of hyperspeed acceleration of what I predicted three years ago. According to a New England Power Generators Association analysis from November 2018, 58 percent of resources in the ISO-New England power market will be "state-sponsored" in less than ten years. It seems reasonable to assume that even this large number may grow still larger.

So we are now at the point in the public policy conversation where we have to rank-order the third-, fourth-, fifth-, sixth- and seventh-best solutions. I hope we in this room could all agree that if states find it necessary to hide the price of carbon reductions through such policies, that they should only dole out the absolute minimum of excess rents necessary to politically obtain decarbonization. Unfortunately, that may not happen, because policymaking in this space exhibits a few things:

1. *Logrolling*. When one special interest gets a handout, others feel entitled to them and politicians, citing fairness, give them, raising costs further and further.

2. *Financially indifferent counterparties to long-term power purchase agreements.* Pass-through entities make it easy for project developers and politicians to get to "yes" because the off-takers are at best indifferent. At worst, these pass-through entities join in the logrolling themselves, cutting themselves in on the development of favored projects or getting other favorable regulatory treatment incorporated into enabling legislation.

3. *Politicians' love for "cutting the ribbon"—while not paying for it.* As we have witnessed in the examples I provided before, long-term arrangements that have unattractive terms are often not revealed for the improvident bets they represent until many years hence. The lost opportunity costs that will result from hardwiring in these projects are not easily visible when the important decisions are being made. And as a practical matter, the ribbon cutting comes before consumers see costs appear on their bills. One generation of politicians can thus reap the political dividends of seeming to do big, bold, environmentally positive things, while suffering none of the political damage of increasing customers' electricity prices.

If left to the current trajectory, we may end up on a path where legislators simply write laws that decree the construction of particular power projects by particular parties—an earmarking policy that is even worse than "integrated resource planning." In my opinion, a useful thought exercise is to imagine a curve of the most economically efficient to least efficient public policies. Where along that curve can political practicality meet economic optimality?

So I leave you in that vein, with a few questions I hope will appeal to our better angels:

1. Is it possible to have states agree, if not on a carbon price, then on some definition of the product that should be acquired to satisfy their clean energy standards?

2. Is there a way to ensure that those faced with a compliance obligation for this product have an economic incentive to engage in least-cost procurements?

3. Is there a way to avoid commitments longer than, say, 5 or 10 years, and instead allow the market's churn to work toward continuing innovations and improvements in efficiency?

4. Is there a way to emphasize the basic framework of a market for electricity, which has served us well, while having a compatible feature to that market that hosts a trade in clean energy attributes of that energy?

5. Finally, is there a way to incorporate sectors other than the power sector into this market?

Ultimately, the tab for the inefficiencies of public policy comes due. The improvidence of the "big bets" of a former generation of regulators and regulated utilities is precisely what led to the emergence of a market orientation to the power markets to begin with. If we can't get everything right to begin with, there is clearly much room for improvement off of the funk of the status quo that we have been handed to grapple with.