September 8, 2017

VIA ELECTRONIC MAIL

TO: NEPOOL PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

RE: Supplemental Notice of September 15, 2017 NEPOOL Participants Committee Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that a meeting of the NEPOOL Participants Committee will be held on Friday, September 15, 2017, at 10:00 a.m. at the Seaport Hotel & World Trade Center, 200 Seaport Boulevard, Boston, MA. The Participants Committee meeting will be held in the Harborview Ballroom (WTC Building) for the purposes set forth on the attached agenda and posted with the meeting materials. For your information, this meeting is recorded, as are all the NEPOOL Participants Committee meetings.

By way of reminder and as previously indicated, the 2017 Regional System Plan public meeting will be held the day before the Participants Committee September meeting, on Thursday, September 14 at 12:30 p.m., at the Seaport Hotel, One Seaport Lane, Boston (Seaport Ballroom in the hotel). Details for the September 14 RSP meeting are available at: https://www.iso-ne.com/event-details?eventId=132300.

We have guaranteed a block of rooms at the Seaport Hotel for the September 15 meeting. If you need an overnight at the “NEPOOL rate” of $339.00 per night, please contact Cindy Jacobs (ckjacobs@daypitney.com; 860-275-0246) and she will add you to the rooming list.

Respectfully yours,

________________________/
/s/  
David T. Doot, Secretary
1. To approve the preliminary minutes of the Participants Committee summer meeting held June 27-29, 2017. The draft preliminary minutes of the summer meeting marked to show changes from the draft circulated with the initial notice are included and posted with this supplemental notice.

2. To adopt and approve the actions recommended by the Technical Committees set forth on the Consent Agenda included with this supplemental notice. Consent Agenda Item No. 4 has been removed and will be considered as Item 8A (see below). As noted below, absent objection the Committee will vote Item 8 below with the Consent Agenda.

3. To receive an ISO Chief Executive Officer (CEO) Report.

4. To receive an ISO Chief Operating Officer (COO) Report. Please note that an update from ISO-NE concerning the ongoing fuel security study was previously circulated to the Committee and also is included with this supplemental notice for your convenience.

5. To discuss the 2018/19 Work Plan and related priorities. A copy of that Work Plan, as circulated with the Initial Notice, also is included with this supplemental notice.

6. To receive a report on the following budgets to be voted at the October Participants Committee meeting:
   a. 2018 ISO-NE Operating and Capital Budgets; and
   b. 2018 NESCOE Budget.
   No vote is planned for this meeting. Background materials detailing the Budgets, along with comments, questions and ISO responses, are included with this supplemental notice and posted on the NEPOOL website.

7. To consider and take action, as appropriate, on an Amended and Restated Generation Information System (GIS) Administration Agreement with APX, Inc. and related changes to a GIS Operating Rule. Background materials and a draft resolution are included with this supplemental notice. Related confidential materials will be circulated under separate cover to Members and Alternates only.

8. To consider and take action, as appropriate, on revisions to ISO New England Planning Procedure (PP) No. 4-1 that describe the Cost Responsibility for Schedule 11 Category C Projects, clarify the treatment of Similar Upgrades, and remove items that are covered as part of the Interconnection Procedures, as unanimously recommended by the Reliability Committee at its August 24, 2017 meeting. Background materials and a draft resolution are included with this supplemental notice. Given the unanimous support for the changes to PP 4-1, this Item should have been included on the Consent Agenda. Absent objection, it will be voted together with the Consent Agenda as part of Item 2 above.

8A. To consider and take action, as appropriate, on revisions to PP 4, Attachment A that provide guidance on transmission cost allocation for transmission projects with multiple parts, as recommended by the Reliability Committee at its August 24, 2017 meeting. This item was removed from the Consent Agenda (Consent Agenda Item 4). Background materials and a draft resolution are included with this supplemental notice.

9. To receive a report on current matters relating to regional wholesale power and transmission arrangements that are pending before the regulators and the courts.

10. To receive reports from Committees, Subcommittees and other working groups:
    • Markets Committee
    • Reliability Committee
    • Transmission Committee
    • Budget & Finance Subcommittee
    • Others

11. Administrative matters.

12. To transact such other business as may properly come before the meeting.
The 2017 Summer Meeting of the NEPOOL Participants Committee was held at The Chatham Bars Inn, Chatham, Massachusetts, on Tuesday, June 27, and Wednesday, June 28, pursuant to notice duly given, followed on Thursday, June 29, by meetings between modified sector groups and ISO Board Members, State Officials, and FERC representatives, respectively. A quorum determined in accordance with the Second Restated NEPOOL Agreement was present and acting throughout the meeting. All motions acted on at the meeting were voted on Tuesday, June 27. Attachment 1 identifies the members, alternates and temporary alternates attending the meeting and voting that day.

Mr. Thomas Kaslow, presided and Mr. David Doot, Secretary, recorded for the meeting.

**JUNE 27, 2017 SESSION**

**EXECUTIVE SESSION**

The June 27, 2017 session began at 9:30 a.m., with discussion in confidential Executive Session during consideration of a proposed slate for election/re-election to the ISO Board of Directors and the confidential proposed settlement of matters set for hearings in the Peak Energy Rent (PER) proceeding (Agenda Item Numbers 1 and 1A, respectively). Except as specifically noted, the only people present during the Executive Session discussions were members, alternates or those Participant representatives specifically designated by the members and alternates for attendance.

**CONFIDENTIAL VOTE ON SLATE OF CANDIDATES FOR ISO BOARD**

Mr. Kaslow introduced Mr. Paul Levy, Chairman of the Joint Nominating Committee (JNC), and Ms. Roberta Brown, JNC and ISO Board Member. Mr. Kaslow explained that the discussion of the slate of candidates would be in Executive Session in order to maintain in
confidence the identity of those candidates being considered for membership on the ISO Board until there was a final ISO Board decision on the slate. Following general comments on the process, Mr. Levy identified the candidates, referring to the confidential package of materials that was circulated to the members and alternates of the Committee in advance of the meeting. He and Ms. Brown offered thoughts on the candidates and the nomination process and then left the meeting.

The slate was then discussed among the members and alternates. Separate from discussion of the candidates on the slate, a number of members noted that PJM members vote on board members on an individual basis rather than on a slate basis. The Committee discussed the history and rationale for NEPOOL’s process. Based on the discussions, the Chairman proposed that the Officers consider this issue separately off-line and report back following that consideration.

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

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

CONFIDENTIAL VOTE ON PER SETTLEMENT

Following that vote, parties in the pending Section 206 FERC proceeding concerning the FCM Peak Energy Rent (PER) mechanism in FCM, including representatives from the ISO, NEPGA and NESCOE, were invited to participate in the Executive Session discussion of a proposed settlement term sheet (the Settlement Term Sheet). Mr. Doot then referred the Committee to the confidential materials on this topic that were circulated to members and
alternates in advance of the meeting and explained that, while each party to the settlement proceeding either joined in the submittal of the Settlement Term Sheet to Settlement Judge Young or had indicated non-opposition, the Settlement Term Sheet would need to be reflected in a formal settlement agreement that had yet to be finalized. He noted that the proposed form of resolution would delegate limited authority to the Officers to approve a final Settlement Agreement if that was the will of the Committee. He reminded the Committee that the settlement information was being presented confidentially and was privileged in accordance with the FERC’s rules of practice and procedure and was not for further distribution.

The key negotiators of the PER Settlement then reviewed the terms with the Committee and responded to questions. Following full opportunity for questions and discussion, the Committee considered the following motion, which was duly made, seconded, and approved by a show of hands vote, with DTE opposing the motion and abstentions by: CMEEC, CLF, CSC, Galt, IECG, Just Energy, LIPA, Mercuria, NH OCA, NextEra, PowerOptions, Reading, Sun Edison, TEC, Utility Services, VEIC, Vitol, VPPSA, and the AR Sector’s Small Load Response and Small Renewable Generation Group Members:

RESOLVED, that the Participants Committee

(1) supports the Settlement Term Sheet that comprehensively addresses all issues set for hearing in Docket No. EL16-120 (concerning the Peak Energy Rent mechanism in the Forward Capacity Market) (the Settlement Term Sheet), dated as of June 15, 2017, as circulated to the Committee prior to its meeting on June 27, 2017, and

(2) delegates to the officers of the Participants Committee the authority, subject to unanimous agreement, to approve a formal offer of settlement reflecting the Settlement Term Sheet, and to the Chairman of the Participants Committee the authority to execute that offer of settlement on behalf of NEPOOL, it being understood that a separate Participants Committee vote would be required if the officers do not unanimously agree on the offer of settlement.
RETURN TO GENERAL SESSION

The Committee came out of Executive Session at 10:30 a.m. and invited all other attendees into the room. Mr. Kaslow welcomed those participating in the Summer Meeting, including members, alternates, and guests, and recognized the ISO Board Members, State Officials, and FERC representatives in attendance. Mr. Doot announced publicly the results of the votes that occurred in Executive Session.

ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), referred the Committee to the written summaries of the ISO Board and Board Committee meetings that had occurred since the May Participants Committee meeting, which were circulated and posted in advance of the meeting. There were no questions or comments on the summaries. There was a discussion of press reports on his presentation at the June 12 Edison Electric Institute Annual Convention in Boston. He said he had expressed his views during a panel discussion that it would be particularly hard to accomplish, through competitive markets, material investment in networked infrastructure subject to open access requirements.

ISO COO REPORT

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), then reviewed highlights from the June COO report, which was circulated in advance of the meeting and posted on the NEPOOL and ISO websites. He explained that the report reflected data for the entire month of May. Focusing on highlights, he reported for May that: (i) Energy Market value was $283 million, up $3 million from April 2017 and up $67 million from May 2016; (ii) average natural gas prices were 4.7% lower than April 2017 average prices; (iii) average Real-Time Hub LMPs ($29.44/MWh) were 6.6% lower than April 2017 LMPs; (iv) average daily (peak hour) Day-
Ahead cleared physical Energy, as a percent of forecasted load, was 97.2% in May, up from 97% in April; (v) daily Net Commitment Period Compensation (NCPC) for May totaled $5.6 million, up $2.5 million from NCPC experienced in April 2017 and $3.6 million higher than NCPC in May 2016; (vi) first contingency payments, totaling $4.5 million, were $1.8 million higher than April’s; (vii) second contingency payments totaled $1 million, up $987,000 from April 2017; (viii) voltage support payments totaled $73,000, down $298,000 from April’s; and (ix) NCPC payments were 2% of the total Energy Market value.

Turning to the average daily Day-Ahead cleared physical Energy, he observed that the percentage of load clearing Day-Ahead for peak hours had been dropping disproportionately over the peak hours. He explained that, while the statistics for May showed that 97.2% of load on average cleared Day-Ahead, there were several days where the load for peak hours that cleared Day-Ahead was more than 1,000 MWh below the actual Real-Time load. He stated that trend was even more pronounced in early June, with the difference between Day-Ahead and Real-Time loads exceeding 1,500-2,000 MWh. The ISO was considering the following possible explanations: (1) Market Participants, like the ISO, could be having a difficulty time forecasting Real-Time load accurately, given the penetration of photovoltaic (PV) resources; and (2) Market Participants might prefer to under-predict load, recognizing that there can be as much as 700-900 MWs of self-scheduled resources in Real-Time, (about half attributable to wind generation and the reminder to imports), which lowers LMPs and correspondingly loads’ costs. In response to a question, he explained that the ISO scheduled based on Day-Ahead cleared physical energy (which drives commitments) and not Day-Ahead Load Obligations. He reminded members that virtual load cleared in the Day-Ahead Market helped to improve market pricing, liquidity, and efficiency, but the ISO’s decisions as to whether supplemental commitments would be necessary
were based on operational considerations. Supplemental Commitments based on Resource Adequacy Assessment (RAA) considerations had not been needed for some time. Dr. Chadalavada agreed in response to a member’s request to discuss further details concerning load obligation variables at either a Participants Committee or Markets Committee meeting.

Commenting on May NCPC, Dr. Chadalavada explained that, of the $5.6 million in total NCPC payments, $4.5 million was for first contingency payments and $1.1 million for second contingency payments. The second contingency payments arose mostly from SEMA/RI on May 19-20, and were primarily the result of outages of two large units in NEMA and SEMA. He reported that for the entire month of May, average Real-Time Load was approximately 12,327 MWh, the lowest average since May 2003.

Dr. Chadalavada reviewed slides highlighting operations on May 18, which was region’s first day of summer heat and high dew points, with load exceeding 20,000 MW and numerous transmission outages and unit outages/reductions. He made special note that a 10% increase in dew points on a hot day could increase load by as much as 2,000 MWs. He summarized and reviewed the May 18 conditions that resulted from the numerous operational constraints, congestion, and divergent pricing during the day. In response to follow up questions, he provided the following details: at the time of the day’s peak, there were outages totaling 8,490 MW (5,700 MW in planned outages; 2,790 MW in forced outages); and the HQ Phase II import limit dropped from 1,760 MW to 1,000 MW, caused by an equipment failure on the line which took about a day or two to correct.

He reported that, on May 18, transmission loading, with accompanying constraints, resulted in a wide-range of LMPs across the system. Notable transmission and reserve constraints affecting pricing included: interface constraints in NH, ME, and VT; North-South
Interface constraints; a roughly 90-minute local Thirty-Minute Operating Reserve (TMOR) constraint in NEMA; and system replacement reserve deficiencies/constraints. As a result, not only was there significant price separation across New England due to congestion, but the average Real-Time Hub LMP during the peak hour reached $389.17 MWh (compared to a Day-Ahead Hub LMP during the peak hour of $100 MWh). He also explained that, in NEMA, Reserve Constraint Penalty Factors (RCPF) for Thirty Minute Operating Reserves (TMOR) were activated (binding), but there were sufficient resources to avoid a TMOR RCPF violation (which would have occurred had prices reached $1,000/MWh without sufficient resources available to satisfy TMOR requirements).

At a member’s request, Dr. Chadalavada reported on a similar event on June 11-13, during which temperatures were in the mid-90s and dew points in the high-60s. He said load on June 12 was 23,100 MW, and increased to 24,000 MW on June 13. Those conditions resulted in an operating reserves shortage in NEMA and the need to dispatch units out-of-merit-order in order to maintain reliability in load pockets.

Dr. Chadalavada clarified in response to questions on these events that the replacement reserve constraint is only a system-wide constraint, whereas operating reserve constraints can be either or both system-wide and local. He agreed in response to another question that the upgrades on the North-South Interface in Greater Boston would have mitigated some of the constraints had those upgrades been operational.

Dr. Chadalavada concluded his presentation by warning members that, while temperatures had been below normal for May and early June, the National Weather Service was forecasting above-normal temperatures for the Northeast later in the summer.
ISO IMM ANNUAL REPORT

Dr. Jeffrey McDonald, the ISO’s Internal Market Monitor (IMM), presented highlights from the IMM’s 2016 Markets Report (IMM Annual Report), which had been circulated and posted in advance of the meeting. Summarizing, he noted lower wholesale power costs and uplift due to lower fuel prices in 2016, with the fuel price for natural gas-fired resources the lowest in 16 years. In response to a member’s question, he noted a 34% decrease in natural gas prices and that total load decreased 2% in 2016. He explained that energy costs were the most variable of the wholesale cost components. He summarized that NCPC and reserve payments decreased by 30-35%. He noted increases of 6% in transmission upgrade costs and 15% in capacity costs (due to changes in Capacity Clearing Prices). Dr. McDonald agreed that mild winters in the past two years had had a downward impact on the price of natural gas in the region, although he acknowledged less confidence in concluding definitively what other factors might drive variations in the region’s natural gas prices.

Dr. McDonald then reviewed a 5-year comparison of total wholesale costs during the first quarter (Q1) versus the remaining quarters of each year. He pointed out that almost all the variability was reflected in Q1, with a nearly direct correlation between total wholesale costs in Q1 and natural gas prices during that time.

Turning to a chart reflecting uplift payments over the past five years, he highlighted that uplift in 2016 was comparatively lower overall, roughly 60% of the amount incurred during 2015, primarily due to Market Rule changes that altered how uplift was calculated for resources committed in the Day-Ahead Energy Market.

Dr. McDonald then reviewed the impact of emission costs (particularly CO₂ credits procured through the Regional Greenhouse Gas Initiative (RGGI)) on the costs of generation.
Though costs had been lower since the Clean Power Plan was put on hold, he concluded that RGGI was adding up to 15% to variable costs of impacted generation, or as much as $3/MWh.

In response to a question on the potential impact of Massachusetts environmental regulations addressing CO₂ emission limits then under development, Dr. McDonald noted that, certainly before all the details had been ironed out, the IMM did not have a reliable estimate of how such costs might be incorporated into offers or add to the figures in the chart. However, he expressed a strong preference for a mechanism that would permit the liquid trading of emissions credits and that focuses on overall reductions. A member stated that concerns over MA regulations and implementation would need to be considered by the Markets Committee, particularly in light of proposed implementation of those regulations by the beginning of 2018 and the ISO’s need for a process to manage impacted resources, which would have limited run hours.

Dr. McDonald then reviewed the load duration curve over the past five years, which reflected a 2% decrease in load in 2016 that was driven primarily by energy efficiency. In response to questions whether the difference in past years at the higher load levels were weather driven, Dr. McDonald stated that load had become more variable/“peaky” over time and it was not clear what was driving the year-to-year systematic differences. He explained that 31% of load was currently met by nuclear generators and about 50% by electricity from natural gas-fired generators. Looking ahead, nuclear and coal-fired resources would be further reduced given the previously announced Brayton Point and Pilgrim retirements with the gap created by those shutdowns to be filled primarily by natural gas-fired resources.

Focusing on imports/exports, he noted that New England continued to be a net importer of power from New York and Canada, receiving approximately 2,400 MW of electricity and
5,000 MW of import capability. He explained that most of the transactions were pre-scheduled and fixed, notwithstanding Coordinated Transaction Scheduling (CTS).

Referencing a chart, he noted that average priced supply was generally sufficient for price-driven dispatch, but during certain load and supply conditions the ISO had very little price-responsive resources to call on. In response to questions, he agreed in future reports to provide more granular analysis. He opined that downward dispatchability of price-responsive supply had increased with the Do Not Exceed Dispatch (DNE) and -$150 offer price floor Market Rule change, but it remained unclear whether new resources would participate through bidding rather than self-scheduling. He agreed to provide a more granular and frequent breakdown of those impacts.

Dr. McDonald then reviewed a chart showing how wind had increasingly helped to set Real-Time clearing prices and how virtual offers in the Day-Ahead Energy Market were helping to achieve efficient pricing convergence between Day-Ahead and Real-Time Energy Markets and helping to improve dispatch and prices in areas where pockets of wind generation were causing over-generation pockets.

He referenced a slide summarizing a relatively high degree of structural competitiveness among supply in the Day-Ahead Energy Market. He noted that, in the Real-Time Energy Market, there were some hours where there were pivotal suppliers, but he was satisfied that existing mitigation measures did and could address those circumstances.

Dr. McDonald concluded his presentation by reviewing charts reflecting that FCM had produced new entry to counter retirements, and capacity prices had declined as the system procured more entry than needed to meet Installed Capacity Requirements (ICR). He reported the Residual Supply Index (RSI) for the capacity market indicated pivotal supplier(s) exist in
nearly all auctions and zones, and noted that mitigation had been applied to address any resulting economic concerns. A member cautioned that past results with respect to new entry may not be indicative of future results, given the out-of-market factors increasingly impacting development.

ISO CFO REPORT

Mr. Robert Ludlow, ISO Vice President, Chief Financial Officer (CFO) and Chief Compliance Officer, referred the Committee to the ISO 2018/19 preliminary operating and capital budget presentation included with the materials posted in advance of the meeting. He reported he had also shared this information with State Officials at the 2017 NECPUC Symposium. He identified and discussed in detail the following key components that were driving changes to the 2018/19 Budgets from 2017’s budgets: increased cyber security costs (8 additional full-time equivalent (FTEs), 5 of which will be new FTEs); increases in compensation/medical and defined contribution pension plans; funding for Competitive Auctions with Subsidized Policy Resources (CASPR) studies and analyses; changes in regulatorily-mandated costs like NERC/NPCC fees; increases for FCM and other related market services; increased computer services and systems support costs; and reductions through efficiencies mitigating and reducing costs, and other cost reductions. He said that the 2018/19 Operating Budgets were projected to increase about 3.5% each year, while the 2018 Capital Budget was projected to be the same as the 2017 Capital Budget.

Focusing on the budget process, Mr. Ludlow reported that the Budget & Finance Subcommittee (Subcommittee) meeting to discuss the 2018/19 Budgets was planned for August 11. The ISO would review those Budgets with the State Officials on August 15 and with the ISO Board’s Audit & Finance Committee on August 17. The ISO would review feedback received
from those three meetings with its full Board on September 14. Plans were for the Participants Committee to vote on the proposed budgets at its October 13 meeting, with the final ISO Board vote to be taken following the October Participants Committee meeting. Mr. Ludlow indicated that the ISO planned to file the 2018 Budgets with the FERC on October 17.

Mr. Ludlow then reported on the status of the ISO’s FTR Balance of Planning Period (BoPP) implementation, as outlined in a memorandum to the Subcommittee and circulated to the Participants Committee. He explained that the ISO recognized in response to a protest filed at the FERC that it needed to make adjustments to at least one of the factors in the calculation of financial assurance margin requirements. In order to facilitate this adjustment and presentation for NEPOOL consideration, the ISO withdrew its April 20, 2017 filing on May 26. Given these circumstances, and the ISO’s continuing work on the price-responsive demand (PRD) and pay-for-performance (PFP) projects, both of which had been accepted by the FERC and had to be completed/implemented by June 1, 2018, the BoPP implementation date would be delayed from the targeted September, 2017 effective date to approximately the third quarter of 2018.

A member complained about the significant delay in the implementation of FTR/BoPP auctions and long-term FTR auctions. He urged more expeditious implementation, perhaps informed by or copying how other ISOs/RTOs have implemented those markets and their associated FERC-approved financial assurance requirements.

APPROVAL OF MAY 5, 2017 MEETING MINUTES

Mr. Doot referred the Committee to the preliminary minutes of the May 5, 2017 teleconference meeting that had been circulated in advance of the meeting. Following motion duly made and seconded, those preliminary minutes were unanimously approved without change.
CONSENT AGENDA

Mr. Kaslow referred the Committee to the Consent Agenda that was circulated in advance of the meeting. Following motion duly made and seconded, the Consent Agenda was unanimously approved, with an abstention by CSC. The CSC representative stated that CSC abstained because there was insufficient understanding of the costs and recovery mechanism for compliance with NERC standards to be implemented by Consent Agenda Item 4 (PP-11 New Procedure for Geomagnetic Disturbances).

PRD FULL INTEGRATION CONFORMING CHANGES

Mr. Alex Kuznecow referred the Committee to the materials circulated in advance of the meeting concerning a package of recommended Tariff revisions in connection with the June 1, 2018 implementation of the full integration of Demand Response Resources (DRRs) into the wholesale energy, reserves and capacity markets. He reported that portions of the PRD full integration changes had been considered separately by the Markets Committee, the Reliability Committee, the Transmission Committee, and also by the Budget & Finance Subcommittee. The majority of the proposed changes presented to and worked through with the Markets Committee, culminated in a vote taken at the June 14 Markets Committee meeting. Other specific Tariff revisions were considered separately by the Budget & Finance Subcommittee at its May 12 teleconference meeting, and by the Reliability Committee at its June 20 meeting. Finally, the Transmission Committee voted on a smaller set of PRD-related changes at its June 22 meeting.

The Committee confirmed, without objection, consideration of the motions collectively. The following motions were then duly made, seconded, and unanimously approved, with an abstention noted by CSC:
RESOLVED, that the Participants Committee supports revisions to Market Rule 1 and Section I.2.2 of the Tariff, as recommended by the Markets Committee at its June 14, 2017 meeting, and circulated to this Committee in advance of this meeting, together with such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

RESOLVED, that the Participants Committee supports revisions to Tariff Sections III.1.5, III.9.5.3, III.12, and I.2.2., as recommended by the Reliability Committee at its June 20, 2017 meeting, and as circulated to this Committee in advance of this meeting, together with such non-substantive changes as may be approved by the Chair and Vice-Chair of the Reliability Committee.

RESOLVED, that the Participants Committee supports revisions to Tariff Sections I.3.9.3 and I.2.2., as recommended by the Transmission Committee, and as circulated to this Committee in advance of this meeting, together with such non-substantive changes as may be approved by the Chair and Vice-Chair of the Reliability-Transmission Committee.

RESOLVED, that the Participants Committee supports revisions to Tariff Section IV.A Schedule 2 and Section I.2.2, as proposed by the ISO, and as circulated to this Committee in advance of this meeting, together with such non-substantive changes as may be approved by the Chair of the Budget & Finance Subcommittee and the Chief Financial Officer of the ISO.

**NESCOE BUDGET FRAMEWORK FOR 2018-2022**

Mr. Ken Dell Orto, Budget & Finance Subcommittee Chair, referred the Committee to the materials circulated in advance of the meeting concerning NESCOE’s third five-year budget framework covering years its operations for years 11-15 (or the 2018-2022 period) (the Third Budget Framework). He explained that the November 21, 2007 Memorandum of Understanding (MOU) among the ISO, NEPOOL and NESCOE required NESCOE presentation of the Third Budget Framework as it had frameworks for years 1-5 and 6-10. That MOU also required that NESCOE’s annual budget not increase more than 15% in any one year or increase by more than 50% on a cumulative basis over a five-year period.
He referred to the NESCOE Third Budget Framework, which the Subcommittee considered at its May 12, 2017 meeting. He summarized that the Third Budget Framework was based on NESCOE’s 2017 annual budget, with 3% annual increases for years 11-15. NESCOE, as it had during its second Budget Framework, had committed not to seek a budget increase of more than 10% in any one year or more than 30% on a cumulative basis during years 11-15, and would use any unspent funds to reduce future year’s collections. He reported that the Third Budget Framework contemplated professional and administrative staffing levels consistent with those in 2016 and 2017, with some flexibility to add one additional professional if and as necessary. He stated there were no objections or concerns raised with respect to the Third Budget Framework.

The following motion was then duly made, seconded, and unanimously approved, with an abstention noted by CSC:

RESOLVED, that the Participants Committee supports NESCOE’s third five-year budget framework, for years 11 through 15 of its operations (2018-2022), as circulated for and presented at this meeting.

LITIGATION REPORT

Mr. Doot referred the Committee to the Litigation Report circulated and posted in advance of the meeting. He summarized at high level the post-technical conference filings with the FERC in Docket No. AD107-11 concerning the impact on markets of States’ public policies, which he explained were similar to the types of issues being discussed in IMAPP.

COMMITTEE REPORTS

GIS Agreement Working Group. Mr. David Cavanaugh referred the Committee to a memorandum summarizing negotiations with respect to an Amended and Restated GIS Administration Agreement Between NEPOOL and APX, Inc. (APX) (the GIS Agreement) that
had been circulated and posted with the meeting materials in advance of the meeting. He also referred to a term sheet provided to APX that formed the basis for discussions to amend and extend the GIS Agreement. He reported that the GIS Agreement Working Group had prepared two documents, one addressing technical issues and the other addressing commercial issues. Those documents were presented to APX, which then provided a proposal and supplements. The most current supplement confirmed that APX was willing to continue the current fee structure, which was a single invoice to NEPOOL based on the number of MWh tracked through the GIS, with the existing annual floor and ceiling, and a per Certificate charge for secondary transfers. He stated that an early draft term sheet was shared with the ISO for its input and reflected its input on the draft term sheet. That term sheet was then shared with APX.

Focusing on what was left to be done, he explained that the Working Group was still discussing how ongoing GIS enhancements should be incorporated into the GIS arrangements and how future changes should be managed. There would be particular focus on how to address modifications to the GIS required to reflect regulatory change, an ISO change, a rule change, or a system change.

Mr. Cavanaugh reminded the Committee that the current GIS Agreement would expire on December 31, 2017, but would automatically be extended by one year unless either NEPOOL or APX provided the other party with a termination notice by October 1, 2017. He stressed the importance of signing an agreement prior to that date, so the Working Group planned to finalize a draft agreement in time for a vote at the September 15 Participants Committee meeting.

Markets Committee. Mr. William Fowler reported that the next Markets Committee meeting was scheduled for July 11-12 at the Doubletree in Westborough, MA, with key items including CASPR and the new rules on reconfiguration and bilaterals and implementation of the
demand curve associated with them. The NEPGA representative confirmed plans to discuss a settlement agreement and explanatory statement with the Markets Committee at that meeting.

Reliability Committee. Mr. Robert Stein reported that a joint summer meeting of the Reliability and Transmission Committees (RC/TC Summer Meeting) was scheduled to meet on July 18-19 at Mills Falls in Meredith, NH. Ms. Mariah Winkler reported the reservations block at Mills Falls was closed but encouraged people that were interested in attending to register on the ISO website and to contact her regarding reservations.

Transmission Committee. Mr. José Rotger also reported that, at the Joint RC/TC Summer Meeting, the Transmission Committee portion of the agenda would focus on the 2017-18 Regional Network Service (RNS) rate, with a presentation by the Transmission Owners on that rate and a 5-year RNS rate outlook.

Budget & Finance Subcommittee. Mr. Dell Orto reported that the Subcommittee was scheduled to meet on August 11 to review the ISO’s proposed 2018 operating and capital budgets and NESCOE’s proposed 2018 annual budget. The Subcommittee was also scheduled to meet on August 23, with the agenda, including a review of any pertinent Financial Assurance or Billing Policy issues, still being determined.

OTHER BUSINESS

Mr. Doot indicated that the next Participants Committee meeting, scheduled to be held August 4 in Boston, was likely to be re-scheduled as a teleconference meeting or cancelled given the relatively few items expected to be ready for Participants Committee discussion at that time. He urged Participants to pay close attention to notices for that meeting.
ISO EMM REPORT

Dr. David Patton, Ph.D., President, Potomac Economics, the ISO’s External Market Monitor (EMM), presented highlights from the EMM’s 2016 Markets Report (EMM Annual Report), which had been circulated and posted in advance of the meeting. Reviewing highlights, he stated New England’s Energy and Ancillary Services Markets performed competitively in 2016. He reported that in 2016: energy prices fell 30%, largely driven by a 34% decrease in natural gas prices, which was consistent because energy offers in competitive electricity markets should track input costs; average load was down 2% due to mild weather conditions during the year, particularly during winter; and there was very little shortage pricing due to a capacity surplus and relatively mild weather conditions. He expected more shortages to occur in the future as surplus supply shrinks, which would lead to higher revenues in the Energy and Ancillary Services Market and use of the penalty pricing regime. He noted the fluctuations in capacity prices resulting from the load/resource balance for each of the recent auctions. As with Energy and Ancillary Services, he projected that capacity prices and revenues would increase as the surplus shrinks.

Dr. Patton compared total uplift costs and uplift costs per MWh of load across the RTOs, noting the significant reductions in uplift payments in 2016 from 2015, primarily in Real-Time uplift. He observed that virtually all of the reductions were due to Market Rule changes in early 2016, that changed how NCPC payments were calculated in the Real-Time Markets. He observed that, even with the very substantial reduction in total uplift costs from 2015 to 2016, uplift costs in New England were still more than double on a per MW basis than those in NYISO and MISO.
He summarized his observations on market competitiveness, noting some market power concerns in Boston and market-wide under high-load conditions, but concluding that the markets performed competitively with very little evidence of economic and physical withholding, or other forms of market power abuses or manipulation. He reported that mitigation was infrequent in the energy markets, effective in preventing the exercise of market power, and implemented consistently with the Tariff, adding additional observations about mitigation measures for local reliability commitment. Suppliers in those instances could have the chance to increase NCPC payments above efficient levels, and the EMM recommended that the ISO consider Tariff changes to expand its authority to address this concern.

He summarized the observations in the EMM report concerning Day-Ahead and NCPC costs and reserve markets, repeating his earlier recommendation that energy and reserves be co-optimized in the Day-Ahead Market. He then responded to a series of questions. He explained that committing resources in the Day-Ahead Market for local second contingency tended to reduce congestion. Virtual trading effectively arbitraged the Real-Time congestion that occurred absent adequate Day-Ahead commitments. He noted that New England saw substantially less congestion in Real-Time as compared to NYISO and MISO. Because of the “lumpiness” of second contingency resources, there was a risk of over commitment Day-Ahead with resulting very low prices in Real-Time, and resulting NCPC uplift. Ensuring co-optimized products in the Day-Ahead Market shifts costs from uplift to market prices would achieve a desired outcome and encourage economic investments where needed. He said that he expected the Greater Boston Upgrades and the new Footprint Power plant to reduce the need for local second contingency commitments.
He summarized the following EMM’s recommendations with respect to NCPC and the reserve markets and the reasons for those recommendations: (1) change the Market Rules to co-optimize Day-Ahead Reserve and Energy Markets; and (2) eliminate the Forward Reserve Market (FRM), which was providing very little value. He clarified in response to questions why he concluded that FRM was not a desired market and his recommendation to eliminate the market rather than work to improve the signals sent by the market.

Dr. Patton referred to a chart in his presentation comparing Real-Time NCPC and virtual load and virtual supply in ISO-NE, NYISO and MISO. He noted that the percent of virtual load versus overall load was 20% of that experienced in NYISO, and 14% of MISO’s experience, with similar effects for virtual supply. He strongly recommended markets with highly liquid virtual transactions, explaining the many positive impacts of such transactions on the Day-Ahead Energy Markets. He explained that poor liquidity in New England translated into poorer convergence between the Day-Ahead and Real-Time prices. He attributed New England’s less desirable experiences with virtual transactions to costs allocated to those transactions, which were much greater than similar allocated costs in NYISO and MISO. Accordingly, the EMM repeated its earlier recommendation to modify the allocation of economic NCPC charges away from virtual load to be more consistent with cost-causation principles (beneficiary pays), and which he said would be more consistent with FERC’s recent Notice of Proposed Rulemaking (NOPR) related to uplift allocation. He cited MISO as having the best practice in this regard and clarified why the EMM was making this recommendation. He warned that the adverse impact to the market caused by impediments to virtual trading would only increase as renewable and distributed resources increase on the system, which would will progressively degrade the performance of the Day-Ahead Energy Market.
Turning to EMM observations concerning external interface scheduling, he observed that Real-Time interchanges between ISO and NYISO were still scheduled in the unprofitable direction in 41% of intervals in 2016. He noted that Coordinated Transaction Scheduling (CTS) had produced significant cost savings, but not as large as possible, primarily because of price forecast errors. He referred the members to the EMM recommendation that the ISO reduce forecast errors by increasing the number of supply curve points that are used to model supply costs in the New England Market, particularly in steep portions of the supply curve and modify its Real-Time software to align ramp assumptions with actual ramp capacity. He said the EMM had made similar forecasting improvement recommendations to the NYISO.

Dr. Patton then summarized a chart reflecting price signals and net revenues for new and existing generation from 2015-2020. He observed that current market prices were insufficient to support new generation resources, and may not support estimated going forward costs for older steam units. He noted the EMM’s conclusion that between 2010 and 2020, 4 gigawatts (GW) of oil- and coal-fired capacity had or would retire as a result of falling prices, phase-in of PFP, phase-out of the Winter Reliability Program, and entry of state-subsidized resources.

Reviewing the portion of his presentation concerning fuel supply and demand during severe winter periods, he noted that the New England region was becoming increasingly reliant on liquefied natural gas (LNG) capacity and oil storage capacity, and that those capacities would be insufficient to meet regional needs during a significant pipeline contingency. Noting that the RTOs base resource adequacy determinations on the summer peak, the fuel supply situation at least raised the question of whether ISO-NE should have winter planning criteria distinct from the summer peak requirements and, if so, whether it should think about a seasonal capacity market. He noted in response to questions that the pipeline contingency referenced was a loss of
a pipeline, which a member pointed out was extremely unlikely, although there certainly could be reductions associated with, for example, compressor failures. He also responded to a number of questions relating to the EMM’s assumptions about growth in renewable and demand response resources. He clarified also in response to questions that the EMM’s recommendation was to evaluate potential benefits of market changes that would complement PFP to ensure fuel security under severe winter conditions, and not that specific changes be made.

Dr. Patton then reviewed his observations on the effects of state-subsidized resources on the markets. He opined that the most cost-effective way to reduce carbon emissions was to develop a non-discriminatory, technology-neutral solution that would accommodate legitimate state policy initiatives but ideally also help to use the markets to achieve those initiatives. He expressed his support for CASPR generally, with the suggestion that the ISO better address the entry of new, non-subsidized resources in the market and provide broader latitude for updated retirement offers in the substitution auction. He flagged for members the relative cost per ton of carbon emission reductions achieved by various technologies, and their relative value in enhancing winter reliability, and also referred to a table summarizing the potential subsidized new entry the region might see in the next five Forward Capacity Auctions. He reported that the EMM filed comments and participated in the FERC’s May 1-2 technical conference where it reviewed its concerns in all the markets it monitors. He concluded his presentation by responding to follow up questions on the EMM’s recommendations.

There being no other business, the June 27, 2017 meeting ended at 4:30 p.m. to reconvene on Wednesday, June 28, 2017 at 8:30 a.m.
JUNE 28, 2017 SESSION

The Summer Meeting reconvened at 8:30 a.m. on June 28, 2017.

OPENING AND WELCOMING REMARKS

After welcoming members and guests, Mr. Kaslow referred the Committee to the Legislative Report that NEPOOL Counsel prepared and circulated at the meeting. He expressed gratitude for the strong attendance by State officials, particularly given the dedicated focus of the region in its efforts to advance public policies of the States through the markets.

Mr. Kaslow introduced NECPUC President Martin Honigberg, Chairman of the New Hampshire Public Utilities Commission, to provide remarks on behalf of the State regulators. Chairman Honigberg thanked NEPOOL for the invitation to participate. He explained that the Commissioners welcomed the refreshing chance for discussion and open dialogue since much of their time was spent adjudicating contested matters with strict rules of engagement. He commented on his representative role with the JNC for the ISO Board selection process. He explained that NECPUC attendance at NEPOOL meetings provided a very valuable means to interact with industry participants and to hear diverse perspectives on issues confronting the region. Such insights could only help regulators as they work to address a wide range of issues including changing markets, IMAPP, siting issues, and the need for more gas infrastructure. He expressed appreciation on behalf of NECPUC to NEPOOL and the ISO for these ongoing processes.

Mr. Kaslow next introduced Secretary Matthew Beaton, Massachusetts Office of Energy and Environmental Affairs, who on behalf of Governor Charlie Baker and Lieutenant Governor Karyn Polito welcomed to Massachusetts those attending the NEPOOL Summer Meeting. He reminded members that he had attended NEPOOL’s 2016 Summer Meeting and said he had...
been encouraged by the collaboration that has occurred since then on IMAPP. He stressed the importance of the region transmitting a positive impression to public policy makers on the work being done to find solutions. He expressed the Commonwealth’s strong desire for success in the effort to integrate markets and public policies and encouraged continued progress in finding an acceptable solution.

**FERC REGIONAL UPDATE**

Mr. Kaslow welcomed the following FERC Staff and thanked them for attending: Mr. Daniel Nowak, Deputy Director, Office of Energy Markets Regulation, Division of Energy Regulation East; Ms. Christy Walsh, Director, Office of Energy Policy and Innovation, Division of Policy Development; Ms. Emma Nicholson, Economist, Office of Energy Policy and Innovation; and Ms. Sandra Waldstein, Director, Office of External Affairs, State, International and Public Affairs Division.

Mr. Nowak said he and his colleagues were looking forward to meeting with Sectors the next day. He cautioned members that FERC staff would not be in a position to provide any opinions or guidance regarding the CASPR proposal. He explained that the FERC continued to operate without a quorum, with no specific schedule then identified for Senate action to confirm Commission nominees Messrs. Neil Chatterjee and Robert Powelson. He noted that Commissioner Colette Honorable was leaving the FERC on June 30, leaving acting Chairman Cheryl LaFleur as the sole Commissioner. He reviewed that, since late January the FERC had been limited on what it could approve. Staff had existing delegated authority to act on certain filings, including the authority to approve uncontested Section 205 filings and uncontested waivers, and had set some cases for hearing and settlement judge procedures where there were just issues of material fact that did not require a ruling on policy issues. In some cases,
respecting statutory requirements, Staff had acted for the FERC by delegated authority to accept filings subject to refund and subject to further order. He said there is a growing backlog of rehearing requests, complaints, and merit orders related to the Section 205 filings.

Ms. Nicholson then summarized Staff’s reaction to the May 1-2 Technical Conference. She thanked NEPOOL, the ISO, and the Market Participants for their participation and for helping to develop a record for the FERC to understand key challenges facing that the Northeast RTOs and ISOs are facing. She reported that the FERC received over 700 pages of comments from over 81 entities. She said that reply comments were due on July 7 but that deadline could change in response to a motion for a one-week extension that had already been received. On FERC’s price formation efforts, she reported that FERC issued final rules on Offer Caps (Order 831) and on Settlement and Shortage Pricing (Order 825). She reported on the pending NOPR to address Fast-Start pricing that was issued in December 2016, with comments received in February 2017, and the NOPR on uplift and transparency, which was issued in January 2017, with comments received in April. She also reported on the November 2016 Electric Storage NOPR, with comments received in February, and on the Large Generator Interconnection NOPR, on which comments were filed in April 2017. She concluded her remarks reporting that FERC Technical Conferences were scheduled on June 29 on natural gas index liquidity and transparency, that a conference was recently held on Bulk Power System Reliability, and that a conference was underway for discussion of increasing market and planning efficiency through improved RTO/ISO software.
ADVANCING PUBLIC POLICIES IN THE WHOLESALE MARKETS

Mr. Kaslow described the plans for the remainder of the morning, explaining that the objective was to provide the region with perspectives on the experiences in other international and national markets of more advanced efforts to further public policy goals.

*International Experiences*

Mr. Kaslow welcomed and introduced Mr. Michael Mehling, Deputy Director of the Center for Energy and Policy Research at the Massachusetts Institute of Technology. Mr. Mehling referred the Committee to his presentation, posted with the meeting materials, of the experiences of European countries, primarily Germany, in advancing clean energy policy goals. He explained that Germany was the 4th largest economy in the world with 82 million people, roughly $3.5 trillion in gross domestic product, and a heavy industrial base driven by manufacturing exports. Germany’s size and economic structure therefore provided an interesting case study.

Mr. Mehling described the German power grid, which included four transmission system operators, one price zone, and approximately 800-850 distribution system operators. He reported that, through most of 20th century, there were about 850 generators serving load in Germany, but that number has since grown to over 2 million. Mr. Mehling said that generation remained somewhat carbon-intensive and that Germany was a net exporter of power.

He went on to refer to broader efforts for a Europe-wide integrated market, reporting that Germany was part of the Northwestern Power Pool and traded heavily with France, Belgium, Netherlands, Luxenbg, Austria, and Poland.
Mr. Mehling explained that European Union (EU) legislators and regulators had been working to liberalize and integrate European energy markets, and had issued directives to the EU members in that regard. Directives included implementation of greater price transparency, integration a market for electricity and gas, and advancing regulations related to EU environmental policy. He stated Germany’s efforts reflect those of the EU.

Mr. Mehling noted that Germany’s aggressive legislative targets related to reducing greenhouse gasses (GHG), increasing renewable energy and increasing energy efficiency. He identified key legislation and then reported that, in the early 2000s, a feed-in tariff was adopted that provided very attractive rates for renewable generation. As a result, Germany experienced a dramatic increase in renewable generation, with penetration growing from less than 5% of average generation to 30-35% of generation from renewables, and, for one week in June 2017, 49.4% of the country’s total electricity generated by renewables.

He reported that one-half of Germany’s nuclear fleet had been decommissioned since Fukushima, with the last nuclear generator scheduled to be taken offline by 2022. He reported that, while there had been a steady downward trend in Germany’s carbon emissions, that trend has plateaued in recent years and Germany would not achieve its 40% greenhouse gas (GHG) target (relative to 1990 levels) by 2020. He explained that the main reason for the decline in carbon reduction rates was that the European carbon market was not sending a sufficient price signal to incentivize switching from coal to gas. Furthermore, the growth of renewables had not displaced as much fossil or thermal generation as might have been expected because Germany continued to export a significant amount of energy to neighboring countries (including the Netherlands, Austria, Switzerland, the Czech Republic and, seasonally, France).
To assess any impact on reliability, Mr. Mehling referred to the System Average Interrupted Duration Index (SAIDI), which measured supply service interruptions that exceed three minutes and were not due to weather alone. In Germany, the annual average interruption duration had declined from over 20 minutes on average per year to less than 12 minutes (the annual average in the US was 200-250 minutes on average per year). Concerning the effect of renewable penetration on wholesale power markets, Mr. Mehling explained that renewables were displacing advanced, lower carbon-intensity thermal generation such as natural gas generation. This outcome mitigated the reduction in carbon intensity and had led to the mothballing of some advanced gas generators. Referring to wholesale power prices, he observed that prices had plateaued overall but were much more volatile with the increase in renewables.

In response to the unexpectedly quick growth in renewable energy generation on the system, much of it at the distribution level, Mr. Mehling explained that Germany had shifted to quantity planning and competitive auctions for new renewable energy capacity. He said this approach provided for greater control over the pace of renewable penetration and gave Germany more time to improve and transform grid infrastructure to deliver renewable power from the north, where there was a lot of wind generation, and to the south, where much of the industrial load was located. He reported that there had been substantial congestion between the north and south, with estimated congestion costs to exceed one billion euros per year in the next few years. He said Germany did not have a robust capacity market similar to those in some US markets. He opined that Germany illustrated how markets could maintain reliability with dramatically increased renewable power, but not without significant effects on the markets and incumbent utilities.
In response to questions, Mr. Mehling confirmed that much of Germany’s coal generation was from less expensive lignite coal, which partially explained why those utilities with high carbon-intensity had done well financially in recent years. Responding to a question about high retail energy prices in Germany, Mr. Mehling explained that the feed-in tariff surcharge accounts for 25-33% of Germany’s retail price and that industrial customers were exempt from the tariff surcharge and other retail fees. However, while retail prices were high, the German public nevertheless supported the expansion of renewables and the decommissioning of the nuclear fleet.

**California Experience Panel Discussion**

Mr. Kaslow recognized Commissioner Sarah Hofmann, of the Vermont Public Utility Commission, as the moderator of a panel to discuss lessons New England could learn from California’s actions to advance public policies in its wholesale power markets. She introduced the following panelists: Mr. Emilio Camacho, Chief of Staff to Commissioner David Hochschild, California (CA) Energy Commission; Mr. Mark Rothleder, Vice President, Market Quality and Renewable Integration, California ISO (CAISO); and Mr. Mark Smith, Vice President, Government and Regulatory Affairs, Calpine Corporation.

**Presentation by Emilio Camacho**

Referring to his PowerPoint presentation that was circulated and displayed, Mr. Camacho explained his position within the CA government, and identified CA’s vision of reducing GHG emissions by 40% below 1990 levels by 2030. He listed the following five goals to achieve CA’s vision: (1) implementing 50% renewable energy by 2030; (2) reducing petroleum consumption in vehicles by 50%; (3) doubling energy efficiency savings at existing buildings; (4) sequestering carbon; and (5) reducing short-lived climate pollutants. He referred the
members to a graph showing progress in reducing GHG emissions since 2000, and then described some of the actions to achieve that progress. He noted that CA was meeting its objective while reducing reliance on nuclear power.

On the topic of energy efficiency in CA, he said CA enacted in 1975 its first codes designed to improve energy efficiency and has since made changes such that CA consumed half the energy per capita as the rest of the nation. Examples were CA requirements for building and appliance efficiency, noting advancements in the efficiencies of refrigerators and televisions over time. He noted that CA adopted in 2016 standards for computers, noting that CA standards frequently become national or international standards because of the size of the CA market. He described CA efforts to use storage in improving efficiency of homes and commercial buildings.

Mr. Camacho then described research and development funding by CA aimed at helping to advance CA’s vision and goals. He reported that CA planned to connect San Francisco to Los Angeles by high speed rail, 100% powered by renewables, noting the challenges in achieving that objective.

Referring to CA Renewable Portfolio Standard (RPS) goals, Mr. Camacho said CA had a goal for 20% renewables in 2013, which had been met, and had a goal for 33% renewables in 2020, which at least one utility had achieved by 2015. There had since been a goal to increase the RPS to 50% renewables by 2030, with a bill under consideration for a 100% RPS goal by 2045. He noted that CA did not count large hydro or rooftop PV solar toward meeting its RPS goals.

With respect to economic impacts, Mr. Camacho reported that the CA solar industry employed over 100,000 workers, indicating that CA projected half of its renewable energy in
2020 would be from solar resources. He explained that CA’s 33 military bases contributed to the
growth of renewables, with the Navy having a 50% renewable goal even before CA, and the
Marines having a goal for zero fossil fuel on its bases by 2025.

Mr. Camacho concluded his presentation by stating that he expected CA’s energy future
to be more decentralized, technology-based, fast changing, and intelligent, with more electric
vehicles, customers with solar, and enhanced two-way communication. He identified Governor
Brown’s disappointment with those denying climate change or refusing to give it the benefit of
the doubt and address it. He summarized CA’s views on climate change and his belief that those
views would prevail.

Members asked questions following Mr. Camacho’s presentation. On the topic of rates
and charges, Mr. Camacho reported that average retail rates were $0.15/ kWh, but Mr. Smith of
Calpine responded as a CA consumer that he was paying a marginal retail electricity rate of
$0.40/ kWh. In response to a member’s comment about the mismatch between CA wholesale
and retail prices, Mr. Camacho referred to CA’s efforts in response to SB 350. He explained that
bill required regulators and CAISO to study barriers to achieving energy successes for
disadvantaged communities. He referred to a SB 350 Barrier Study that included 13 policy
recommendations.

Presentation by Mark Rothleder

Mr. Rothleder provided his perspectives given his experience at CAISO. He described
his background and explained that CAISO operated 80% of the transmission grid in CA,
including the service territories and systems of Southern Cal Edison, San Diego Gas & Electric,
and Pacific Gas & Electric among others. He said CAISO had 30 million customers and
oversaw a $9 billion market. He listed the factors driving unprecedented change in the electric
industry, including the change in the Federal administration, ever-increasing renewable energy goals, efforts to reduce GHG emissions, grid modernization, consumer-owned power, transmission and distribution systems interface, gas storage challenges, community choice, regional collaboration, and fossil plant retirements.

He said that CA had peak wind production of approximately 5,000 MW and peak solar production of approximately 10,000 MW, with an additional 5,000 MW of behind-the-meter solar. He said CA would meet its 33% 2020 RPS goal ahead of schedule and needed to assess how it would handle future goals of 50% and higher. He expected growth in solar, geothermal, and wind resources. He stated the CA PUC was conducting an Integrated Resource Plan for achieving the 50% renewable goal.

Mr. Rothleder then provided some projections. He thought it likely that CA would have approximately 12,000 MW of solar facilities by 2020. He explained how that amount of penetration impacts the “duck curve” of net demand (load minus variable resources (wind and solar)). He reported that CAISO correctly predicted how net demand would impact operations but had underestimated how quickly solar would be added to the system. He said the impact had been to place a substantial premium on the need for flexible grid resources and potentially gas-fired resources. CA experience oversupply at net demand approaching 12,000-13,000 MW, requiring either that energy be exported, stored or curtailed. He explained that mid-day oversupply conditions would only last for a few hours, because as soon as the sun sets there was a steep, long ramp that was expected to get even steeper and longer as solar renewables increase. By way of example, he referred to operations on April 23, 2017, when at hour 16 about 58% of load was met by wind and solar, 65% by renewable resources, and 83% by carbon free-resources. When evening load ramped and the sun set, between hours 16 and 21, imports met
about 47% of the load, gas-fired resources about 37%, and 16% of the load was met by hydro-electric facilities.

He then described and summarized the following future challenges/opportunities:

- Dispatch must be achieved to manage oversupply, minimize curtailment and realize environmental goals;
- New price patterns would provide financial incentive for responsive demand and energy storage;
- Operational performance must be maintained during periods of increased supply variability;
- Enhanced forecasting would become increasingly important to manage supply uncertainty; and
- Fault resiliency capability must be improved. CAISO was working with other reliability organizations, resources, and inverter manufactures to develop and implement short-, medium-, and long-term plans to address this.

Mr. Rothleder predicted the potential for the August 21, 2017 solar eclipse to reduce CA solar production by as much as 65% (5,600 MW) over a three-hour period, which suggested the potential need for supplemental reserves to meet load during the ramp. He estimated that CAISO might see a ramp of as much 98 MW/min as the solar eclipse passed. He concluded by suggesting CAISO needed/would experience growth in the following areas in the future: energy storage; dispatchable demand response; time-of-use rates; minimum generation; western Energy Imbalance Market expansion; regional coordination; electric vehicles; and flexible resources. He emphasized that CA was investing heavily in renewables and CAISO saw its goals as the market operator to ensure reliable and economic grid operations to maximize the benefit of the renewable resource investment.

**Presentation by Mark Smith**

Mr. Smith explained that his presentation, which was circulated to the members, would provide Calpine’s perspective as a participant in CA’s power markets and would review lessons
learned for New England. He referred to substantial administrative entry (i.e., paid out-of-market), reporting that there had not been any new merchant asset enter the CA market for over 10 years. CA, instead, had produced a bilateral capacity trading pattern that had resulted in price discrimination between new resources and existing resources. He reported significant financial stress on conventional thermal resources, without a clear market-driven means to handle retirements of those resources. He acknowledged that CA had been remarkably successful in growing its renewable energy and reducing GHG emissions, but that had been at a substantial cost, with residential rates as high as $0.40/kwh ($400/MWh) for some customers. He stated New England, in its IMAPP process, was presented with a dramatic choice and encouraged swift action to improve the markets and to avoid the very costly circumstances of CA.

In comparing CA and New England, Mr. Smith stated that both regions had very aggressive GHG and RSP goals. The two regions differed, though, in where they stood with respect to solar PV market penetration. He reported CA had a centralized capacity planning mechanism that looked out 10 years and a resource adequacy requirement that was imposed on load serving entities and satisfied bilaterally rather than through a separate RTO-administered market. If CA’s long-term planning suggested a future shortage, either in a very constrained local area or more generally, CA would need to issue an administrative request for proposals and bring on new capacity. For public policy reasons, CA had supported administrative entry of 15,000-20,000 MW of new renewable power.

The advancement of public policies in CA had resulted in many hours of zero or negative energy clearing prices, with premium prices not earned until late in the evening. Desirable, efficient and flexible natural gas generation turned on in the late afternoon and turned off in the early morning, which was completely opposite to the expected, historically normal dispatch
cycle for those resources before the State-sponsored renewable generation was added to the grid. He explained that some of the combined-cycle units were routinely being paid uplift because they must run down to minimum load at low or negative prices. Even peaking facilities were proving uneconomic in the CA market. He summarized a number of CAISO initiatives aimed at addressing the growing operational needs. Those included a flexible ramp product, flexible forward capacity requirements (Flex RA), and changes to capacity counting rules, noting the Effective Load Carrying Capability for a new incremental solar project was close to zero, even though they might have a strong average capacity evaluation.

Mr. Smith stated that CA had been very effective in paying to get new resources online, but leaving too little revenue for existing conventional resources (e.g., paying $150-$200/kW-yr for new resources and $12-$36/kW-yr for existing resources). He referred to a chart of the financial returns based on the various revenue streams for a typical combined cycle among three CA Bay Area plants. He reported that two of the plants were not covering their fixed operating costs. He indicated he did not believe such circumstances immediately threatened reliability, but questioned how long companies could operate in those circumstances. He stated that CA was on a path to a grid comprised of renewables and Reliability Must-Run Agreements (RMRs). He said that reminded him of the Devon Power situation that sparked development of New England’s Installed Capacity Market. He did not think the CA situation would create a reliability crisis but advocated for a more organized and efficient means for managing large scale retirement of conventional resources from the market.

Mr. Smith concluded by describing Calpine’s experiences with four fast-start LM6000 GE turbines. Each had a capacity of 45 MW, could start in 15 minutes, met the duck curve very well, but had high fixed costs and did not receive any marginal revenue for energy. The bilateral
market did not support them, in large part because load serving entities, without knowing how much load they would serve in the future, were not willing to enter into long-term contracts for those resources. The contracts Calpine had for those resources expired before the end of 2017, so Calpine had advised CAISO of its intent to remove these uneconomic resources from service if they were not needed for reliability. CAISO had determined that two of the four were needed for local reliability reasons, and those would be operated pursuant to full cost-of-service RMRs. Lessons he believed New England should take from the CA experiences included: observe and manage the enormous disconnect that can occur between wholesale rates and retail rates; acknowledge that administrative entry will clearly effect the wholesale market; and prepare for the potential growth of solar and re-emergence of RMRs.

**Committee Discussion**

Participants then asked questions of and discussed the presentations from the panel. An NRG representative described that company’s experiences with legacy assets and new renewable projects in CA that have benefited from the administrative entry. NRG confirmed its experiences with a zealous approach to administrative entry, administrative planning, a bilateral and planning driven system that had been successful at achieving its goals but that had introduced a lot of very challenging consequences. NRG continued to advocate in CA for a transparent, visible price signal, market-based structure where there were means not only for administrative agencies to trade off one thing for another, but for the market and market actors to see those trade-offs. Its lesson for New England: beware of the unintended consequences of administrative actions that, in the end, would add expenses for customers.

A NextEra representative reported that its system also included substantial wind and solar assets in CA -- over 2,500 MW and all built under long-term contracts. She observed that, while
the Power Purchase Agreement (PPA) model certainly supported development, such development could harm the competitive wholesale markets. Heavy reliance on PPAs to meet state policies would harm New England’s wholesale power market. She stated there was no market anymore in CA and there were no investment signals for any new merchant build. She urged that New England avoid those consequences. New England, unlike CA, had a forward market that produced somewhat stable revenues for new investment. NextEra would continue to strive for market improvements, possibly that price carbon, that have rules that can be relied upon, that appropriately balance risk, and that allowed for financeability of new investments. She said the economics of wind and solar were improving. NextEra predicted that, by 2020, the market without subsidies could see $0.02-$0.03 for wind, $0.04 for storage, and $0.03-$0.04 for solar with the right weather conditions, wind conditions, and development costs. Given its experiences in CA and elsewhere, NextEra intended to continue its IMAPP efforts with proposals designed to allow all resources to compete in resource-neutral markets that would advance state carbon goals.

The EnerNOC representative volunteered that Company’s perspective on how demand response worked in CA compared to New England. She explained that demand response in CA was more of a utility program, expanding to include an auction mechanism so utilities could meet their goals. EnerNOC noted the opportunities in the Northeast for demand response to participate more actively and directly in the wholesale markets, and indicated it was advocating for evolution in the CA markets in that direction.

The Brookfield representative reported that Brookfield owned about 400 MW in CA, mostly wind but also including one hydro facility, which had some operational challenges relating to the extreme variability in rainfall. He explained that the Brookfield wind facilities
were all supported by long-term PPAs that were starting to roll off. Unless circumstances evolved to provide a more assured revenue stream following termination of the PPAs, the Company may not be willing to invest capital for the continued operation of those assets.

In response to questions concerning the CA market given very high penetration of renewable generation, Mr. Rothleder noted that CA was also confronting the policy change to reduce or eliminate once-through cooling for coastal resources. He said there were 8,000-10,000 MW of those resources that he expected would either be retired or repowered because of that regulatory change. As a result, CA risked losing flexible resources. He said CAISO had been pushing for a multi-year look-ahead perspective on resource procurement and resource adequacy and advocated for a procurement mechanism designed to achieve the right mix of resources for operating the system. He acknowledged that market changes needed to factor in the impact of renewables on market signals for procuring the right mix of resources.

On this topic Mr. Camacho noted that political changes would necessarily impact markets. In CA, there had been substantial concerns relating to environmental justice and the impact of changes in the industry on disadvantaged communities (e.g. Oxnard). Those concerns necessarily needed to be considered and responded to by regulators and CAISO.

The Committee discussed together the effects of the CA market on conventional generators. Mr. Smith said that the impacts on the energy and ancillary services markets of increased renewables penetration was known as far back as five years earlier. CA knew that revenues for conventional generation would shrink, so what was surprising was how quickly it happened.

The panel discussed what impact expansion of the fleet of electric cars would have on gross demand and the duck curve, particularly if there remained a disconnect between economic
signals in the wholesale and retail markets. Mr. Rothleder stated that with 1 million electric vehicles, depending on the type of charging, demand would increase by about 700 MW to 1,000 MW, with much of that increase happening closer to the head of the duck if there were not different incentives in the market. He stated that CA needed to provide incentives to charge during the low net demand conditions (the belly of the duck), and efforts were underway to do that. Mr. Camacho added that CA currently had about 300,000 electric vehicles, may not see a million by 2020, but had been pursuing incentives to grow the electric vehicle fleet to five million. He reported that CA had a project with the Travis Air Force Base, in which the electric vehicle fleet was used to provide grid services, that might inform future activities. Referring back to discussion about retail rates, he added that CA customers’ average rate was $0.15 kW/h, but that what people cared most about was their bill which had been lower in CA because of efficiency gains.

Mr. Rothleder took the opportunity to emphasize that CAISO viewed its responsibility to operate the Day-Ahead and Real-Time markets as designed while supporting CA’s policy goals as best as it could. He expressed support for changes that would incorporate GHG costs into bids and dispatch. He also noted CAISO’s role in transmission planning in supporting state policy objectives and identifying transmission changes required to maintain a reliable and economically efficient system.

Following Mr. Kaslow’s expression of thanks for all who participated in the morning’s discussion, the June 28 session recessed at 12:00 p.m., with members reminded of the following morning’s modified Sector breakout meetings the with the ISO Board, State Officials and FERC representatives.

**RECOGNITION OF JOEL GORDON**
During the banquet that evening, the Committee endorsed by acclamation the following resolution of appreciation for immediate-past Chairman of the Committee, Mr. Joel Gordon:

RESOLUTION OF APPRECIATION

Joel S. Gordon

WHEREAS, Mr. Joel S. Gordon, has faithfully served as the Chairman of the New England Power Pool (NEPOOL) Participants Committee from 2014 through 2016, following five years as the Supplier Sector Vice-Chair and distinguished service for many years prior as a NEPOOL representative and leader; and

WHEREAS, during his tenure, Joel was dedicated to increasing the visibility, reputation and effectiveness of NEPOOL for its members; and

WHEREAS, Joel successfully brought together markets and state policy interests through the NEPOOL IMAPP stakeholder process and established stronger relationships and open dialogue between NEPOOL, NECPUC, NESCOE and the states; and

WHEREAS, Joel has consistently driven NEPOOL in its mission “to create and sustain open, non-discriminatory, competitive, unbundled, markets for energy, capacity and ancillary services (including operating reserves) that are (i) economically efficient and balanced between buyers and sellers, and (ii) provide an opportunity for a participate to receive compensation through the market for a service it provides, in a manner consistent with proper standards of reliability and the long-term sustainability of competitive markets”; and

WHEREAS, Joel significantly increased NEPOOL’s presence in the business priority planning process and secured NEPOOL-directed priorities in energy market pricing, capacity market enhancements, economic planning and improvements to support new entry; and

WHEREAS, under Joel’s leadership, NEPOOL uniquely expressed its own proposed market rule changes twice at the FERC under Section 205 of the EPA using the Jump Ball provisions; and

NOW, THEREFORE, the Participants Committee of the New England Power Pool, on behalf of the NEPOOL Participants, hereby expresses its sincere appreciation to Joel for his service as its Chairman over the past 3 years and for his leadership and dedication to NEPOOL as THE stakeholder process for wholesale electric market rules in New England.

JUNE 29, 2017 SESSION
The June 29 session of the Summer Meeting convened at 8:00 a.m., in modified Sector breakout meetings with the ISO Board, State Officials, and FERC representatives, which continued until 12:15 p.m. With no further Committee business thereafter, the Summer Meeting adjourned.

Respectfully submitted,

David T. Doot, Secretary
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CONSENT AGENDA

Markets Committee Actions

From the notice of actions of the August 8-10, 2017 Markets Committee meeting, dated August 14, 2017, which has been previously circulated:

1. **Revisions to Appendix F to Market Rule 1 (NCPC Modifications for Ramp Constrained Down Resources)**

Support revisions to Appendix F to Market Rule 1 (MR1) to support Net Commitment Period Compensation (NCPC) Modifications for Ramp Constrained Down Resources, as recommended by the Markets Committee at its August 8-10, 2017 meeting, with such further non-material changes as the Chair and Vice-Chair of the Markets Committee may approve.

The motion to recommend Participants Committee support was approved unanimously.

2. **Revisions to MR1 (Small Generator Modeling Options Proposal)**

Support revisions to MR1 to implement the Small Generator Modeling Options Proposal (to allow generators less than 5 MW that would otherwise be eligible to register as Settlement Only Resources (i.e. “small generators”) to remain in the ISO Real-Time systems without having to receive and respond to electronic dispatch instructions when the Resource Dispatchability requirements go into effect), as recommended by the Markets Committee at its August 8-10, 2017 meeting, with such further non-material changes as the Chair and Vice-Chair of the Markets Committee may approve.

The motion to recommend Participants Committee support was approved unanimously.

Reliability Committee Actions

From the notice of actions of the August 24, 2017 Reliability Committee meeting, dated August 24, 2017, which has been previously circulated:

3. **Revisions to PP 9 (Update References, Clarifications)**

Support revisions to ISO New England Planning Procedure (PP) No. 9 (Major Substation Bus Arrangement Requirements and Guidelines) to standardize substation layouts for new and significantly modified Major Transmission Substations and require Independent Pole Tripping on new 345 kV breakers, as recommended by the Reliability Committee at its August 24, 2017 meeting, with such further non-material changes as the Chair and Vice-Chair of the Reliability Committee may approve.

The motion to recommend Participants Committee support was approved unanimously, with one abstention in the Supplier Sector.

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1 Markets Committee Notices of Actions are posted on the ISO-NE website at: [https://iso-ne.com/committees/markets/markets-committee](https://iso-ne.com/committees/markets/markets-committee).

2 Reliability Committee Notices of Actions are posted on the ISO-NE website at: [http://iso-ne.com/committees/reliability/reliability-committee](http://iso-ne.com/committees/reliability/reliability-committee).
4. **REMOVED FROM CONSENT AGENDA.**

Support revisions to PP 4 Attachment A (Supplemental Guidelines for Pool-Supported PTF Cost Review) to update the list of non-exclusive examples for types of projects that would be considered to contain Localized Costs and the list of non-exclusive examples for types of projects that are not likely to contain Localized Costs, as recommended by the Reliability Committee at its August 24, 2017 meeting, with such further non-material changes as the Chair and Vice-Chair of the Reliability Committee may approve.

The motion to recommend Participants Committee support was approved, with four oppositions in the Publicly Owned Entity Sector.

From the notice of actions of the *July 18-19, 2017 Reliability Committee* meeting, dated July 20, 2017, which has been previously circulated:

5. **Revisions to OP-8 (Update References, Definitions)**

Support revisions to Operating Procedure (OP) No. 8 (Operating Reserve and Regulation) to update and correct references, add definitions disclaimer and update Reserve definitions to incorporate Tariff Section I definitions for “Regulation”, “TMNSR”, “TMSR”, and “TMOR”, as recommended by the Reliability Committee at its July 18-19, 2017 meeting, with such further non-material changes as the Chair and Vice-Chair of the Reliability Committee may approve.

The motion to recommend Participants Committee support was approved unanimously.

From the notice of actions of the *June 20, 2017 Reliability Committee* meeting, dated June 20, 2017, which has been previously circulated:

6. **Revisions to OP-20 (Biennial Review)**

Support revisions to OP-20 (Analysis and Reporting of Power System Incidents), pursuant to a biennial review, to conform OP-20 to NERC Reliability Standard MOD-033 (Steady-State and Dynamic System Model Validation) and to reflect minor grammatical changes and clarifications, as recommended by the Reliability Committee at its June 20, 2017 meeting, with such further non-material changes as the Chair and Vice-Chair of the Reliability Committee may approve.

The motion to recommend Participants Committee support was approved unanimously.

7. **Revisions to OP-23 (Clarifications to Reactive Capability Auditing Requirements for Maximum Lagging and Leading Capability)**

Support revisions to OP-23 (Generator Resource Auditing) to clarify the reactive capability auditing requirements for maximum lagging and leading capability, as recommended by the Reliability Committee at its June 20, 2017 meeting, with such further non-material changes as the Chair and Vice-Chair of the Reliability Committee may approve.

The motion to recommend Participants Committee support was approved unanimously.
CONSENT AGENDA (cont.)

8. **Revisions to PP 3 (Performance Requirements Clarifications; Addition of Appendix "D" (Transient Voltage Criterion))**

Support revisions to PP 3 (Reliability Standards For The New England Area Pool Transmission Facilities) to clarify performance requirements and add transient voltage criteria, as recommended by the Reliability Committee at its June 20, 2017 meeting, with such further non-material changes as the Chair and Vice-Chair of the Reliability Committee may approve.

The motion to recommend Participants Committee support was approved unanimously, with one abstention in the Transmission Sector.

**Transmission Committee Actions**

From the notice of actions of the *July 18-19, 2017 Transmission Committee* meeting, dated July 20, 2017, which has been previously circulated:

9. **Revisions to Appendix 3 to OATT Attachment K (Approved QTPS List Updates)**

Support revisions to the list of Qualified Transmission Project Sponsors (QTPSs) in Appendix 3 to Attachment K of the Open Access Transmission Tariff, as recommended by the Transmission Committee at its July 18-19, 2017 meeting, with such further non-material changes as the Chair and Vice-Chair of the Transmission Committee may approve.

The motion to recommend Participants Committee support was approved unanimously.

From the notice of actions of the *June 22, 2017 Transmission Committee* meeting, dated June 22, 2017, which has been previously circulated:

10. **Revisions to Tariff Section I.5 (Force Majeure Application Clarification)**

Support revisions to Section I.5 of the ISO New England Transmission, Markets and Services Tariff (Tariff) to clarify the application of *Force Majeure*, as recommended by the Transmission Committee at its June 22, 2017 meeting, with such further non-material changes as the Chair and Vice-Chair of the Transmission Committee may approve.

The motion to recommend Participants Committee support was approved unanimously, with one abstention in the Supplier Sector.

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3 Transmission Committee Notices of Actions are posted on the ISO-NE website at: [https://www.iso-ne.com/committees/transmission/transmission-committee](https://www.iso-ne.com/committees/transmission/transmission-committee).
TO: NEPOOL PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

Ladies and Gentlemen:

Please find attached the following documents, each of which has been posted on the NEPOOL and ISO websites:

(i) a copy of the August COO report (reflecting data for the full month of July); and
(ii) an ISO-NE update on its fuel security study.

On the fuel security study update, the ISO writes that, “in response to discussions with the NEPOOL officers and representatives of the New England states, ISO New England is providing an update on the status of its fuel security study. This operational analysis is currently underway and will be concluded by the end of October.” During those referenced discussions, your officers had reinforced with ISO management the various concerns raised at and after the Summer Meeting about process and assumptions for, and perceived intentions with respect to, the ISO’s fuel security study. ISO responded at the leadership meeting and has summarized that response in the attached update. Our perception of the meeting was that the ISO’s response helped to reduce the officers’ concerns. You may want to get your officers’ perspectives directly. While the ISO has made clear that the issuance of the study results in October are intended to be the start of stakeholder discussions on fuel security with the benefit of a better understanding of the challenges the region faces, the officers have suggested that time be set aside at the September 15 Participants Committee for potential discussion of this matter if desired. We encourage you to raise any questions or comments directly with your officers or NEPOOL Counsel so we can prepare for that potential discussion.

Hope you all continue to enjoy your summers.

Patrick M. Gerity | Attorney at Law | Attorney Bio

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BOSTON | CONNECTICUT | FLORIDA | NEW JERSEY | NEW YORK | WASHINGTON, DC
An Update on ISO New England’s Study on Regional Fuel Security

ISO New England, the operator of the region’s bulk power system and wholesale electricity markets, is conducting a study of fuel security challenges to the continued reliability of New England’s power system. In this context, fuel security refers to the ability of power plants to have or obtain the fuel required to generate electricity, especially during the winter peak season.*

ISO New England is focused on fuel security for several reasons. The regional power system is increasingly dependent on natural gas for power generation; the capacity of the region’s natural gas infrastructure is not always adequate to deliver all the fuel needed for both heating and power generation during winter; the region has limited dual-fuel generating capability, with emissions restrictions on burning oil; coal, oil, and nuclear power plants, which are needed to maintain reliability when natural gas is in short supply, are retiring; and natural gas is the fuel of choice for most new power plant proposals.

The purpose of the fuel security study is to examine how anticipated generating resource and fuel-mix combinations could impact reliable operation of the regional bulk power system during the winter period. This is an operational study focused on availability of energy during the entire winter period, which is defined as December 1 through February 28 of the following year, and different from a planning study that typically focuses on capacity availability during winter peak days.

This is the first operational study conducted by the ISO to focus on the effect of fuel supply on power system operations throughout an entire winter. As a result, a new study model had to be developed. The model includes more than twenty hypothetical combinations involving different regional resource mixes. These hypothetical future conditions were developed based on a range of resource and fuel types that might be expected to be available in the 2024/2025 timeframe.

Each case is populated with differing levels of non-natural-gas generator retirements, imports from neighboring power grids, dual-fuel power plants (that can generate electricity using natural gas or oil), liquefied natural gas (LNG) imports, and renewable resource development. All the cases take into account the ISO’s forecasts for demand reductions provided by energy efficiency measures and distributed solar generation during this timeframe.

This study will quantify each case’s fuel security risk—that is, the number and duration of energy shortfalls that could occur during the entire winter period in 2024/2025 and that would require implementation of emergency procedures to maintain reliability. These energy shortfalls are to be viewed as a measure of system stress, with increased shortfalls signifying increased risk and, conversely, fewer shortfalls indicating a lower risk.
It’s important to note that the study is not focused on the effects of expanded access to natural gas from the region’s pipeline network and will not identify needs for new or expanded pipeline capacity or natural gas infrastructure.

The study is still underway, with completion expected by the end of October, 2017. Because of the new operational focus of this study, and that both the model and preliminary results must be confirmed, it would be premature to focus stakeholder discussion on the inputs to the study. The preliminary set of results will be presented to regional stakeholders for full discussion, at which point the ISO would be able to conduct additional analysis based on stakeholder feedback. Following discussion of the results, the ISO will work with stakeholders to determine whether further operational or market design measures will be needed to address the fuel security risk.

* The ISO conducted an unrelated Peak-Gas-Day Capacity and Energy Analysis as a continuation of the 2016 Economic Study: NEPOOL Scenario Analysis. The ISO conducts economic studies such as this at the request of stakeholders as part of the regional system planning process. The NEPOOL natural gas study evaluated the natural gas system’s ability to meet the requirements of natural-gas-fired generation as outlined in the stakeholder scenarios used in the 2016 NEPOOL Scenario Analysis. The NEPOOL study assumed that the natural gas system will have no planned or forced outages and the gas delivery system will be at full capacity on the summer and winter peak days in 2025 and 2030, while this Fuel Security Study quantifies the risks associated with insufficient fuel during the entire 90-day winter period. The NEPOOL analysis also differs from this fuel security analysis in terms of metrics, scenarios, and the variability in power system inputs.
Discussion of the ISO’s Draft 2018 Annual Work Plan

Vamsi Chadalavada
EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER
Objectives and Highlights

• Active development of a near-term solution to accommodate state sponsored policy resources into the Forward Capacity Market construct is underway with stakeholders (i.e., CASPR)
  – ISO is targeting a filing by Q4 2017 to allow for FCA13 implementation

• The ISO has provided advance notice of its plans to kick off stakeholder discussions at the Reliability Committee in the fall of 2017 on its Operational Fuel Security Study
  – Discussions on the study are planned from Q4 2017 through Q1 2018
  – The ISO anticipates initiating a stakeholder process in Q2 2018 to determine whether further operational or market design measures will be needed to address the region’s fuel security risk
Objectives and Highlights, Continued

- The ISO continues to seek opportunities to assess improvements to the day-ahead co-optimization functions to better procure and price reserve products
  - While this topic was delayed due to other emerging work, the ISO continues to hold it as a priority and plans to move it back into its 2018-19 work plan

- Initially, the ISO intends to hold technical sessions explaining why improvements may be warranted

- Simultaneous design/implementation of Multi-Period Ramping and Day-Ahead Co-optimization might not be possible and, in that case, the ISO will discuss with stakeholders which project to advance first
Objectives and Highlights, Continued

• Assessment of Delayed Commercial Operation of New Resources
  – The ISO is reviewing the current rules around the treatment of new capacity resources that do not achieve their planned commercial operation date

• Cyber Security will continue to be a major area of emphasis in 2018
  – In addition to a NERC/NPCC audit of CIP Version 5, the ISO plans to continue to implement various cyber security related infrastructure improvements
  – The ISO recently established and plans to fully staff the cyber security operations group to enhance compliance monitoring
Objectives and Highlights, Continued

• The ISO will implement two major projects in June 2018 that will consume a vast majority of the ISO’s capital development resources from Q1 2018 through late Q2 2018:
  1. Price Responsive Demand (PRD)
  2. FCM Pay-For-Performance (PFP)
## Planning/ Operations Related Activities

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<thead>
<tr>
<th></th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
</tr>
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<td>Q4</td>
<td></td>
<td>Q1</td>
<td>Q2</td>
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<td>Operational Load Forecast: PV Integration (slide 8)</td>
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<td>Transmission Planning Studies (slides 10-11)</td>
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<td>Regional Transfer Limits (slide 19)</td>
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<td>FCA 12: Stakeholder and Regulatory Review of ICR/LSR (slide 17)</td>
<td>FCA 12/ ARA 3 CCP9 (slide 21)</td>
<td>ARA 1: CCP11 (slide 21)</td>
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<td>Long-Term 2018 Forecasts (PV, EE, Load) (slide 16)</td>
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<td>FCA 13: Stakeholder and Regulatory Review of ICR/LSR (slide 18)</td>
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<td>FCA 12: Stakeholder and Regulatory Review of ICR/LSR (slide 17)</td>
<td>FCA 13: Stakeholder and Regulatory Review of ICR/LSR (slide 18)</td>
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<td>2017/2018 Winter Reliability Program (slide 22)</td>
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<td>Operational Fuel Security Study (slide 23)</td>
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<td>Black Start Review (slide 24)</td>
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<td>Generator Interconnection Studies (slide 26)</td>
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<td>NERC/FERC Compliance/Cyber Security (slides 27-29)</td>
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<tr>
<td>RSP 2017</td>
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PLANNING/OPERATIONS RELATED ACTIVITIES
Operational Load Forecast: PV Integration

- The influx of behind-the-meter photovoltaic (BTM PV) generation could cause increased error in Load Forecast accuracy.
- Existing forecasting methods require a greater level of sophistication as BTM PV grows to be a considerable portion of the New England resource mix.
- This project will incorporate the effects of BTM PV generation on net system load into the Day Ahead and Seven-Day Load Forecasts.
- The targeted date for completion is Q4 2018.
Order 1000 Implementation

• Implementation efforts are underway
  – ISO focus will be on internal procedures and documentation
  – Review of Planning Procedures will continue to ensure that all processes are well coordinated
  – As we learn from the experiences of other regions with regard to the competitive transmission environment and associated costs, and gain our own experience, further changes may be developed

• Planning for Public Policy
  – ISO completed the first cycle of Planning for Public Policy in June 2017
  – Timing of the next cycle has not been established at this point; the Tariff requires a cycle at least every three years
Transmission Planning Studies

- Updated Needs Assessments and solution development will be conducted in 2017/2018, in accordance with the Planning Process
  - Updated regional load forecast, Energy-Efficiency (EE) forecast, and Solar PV forecast
  - Resource mix will be adjusted for the results of the first 12 Forward Capacity Market Auctions
    - New Resources
    - Resource Retirements and de-list bids
    - Other resource changes
  - Incorporate probabilistic methods in the development of dispatch scenarios being considered
Transmission Planning Studies, cont.

- ISO will continue to improve and update assumptions related to its reliability analyses by capturing both probability and condition/event-driven scenarios, as discussed in 2017
  - The ISO is in the process of capturing probability driven scenarios in the base cases for Needs Assessments
  - The event-driven scenarios, looking at atypical low frequency outages that could have a high impact to the system, will be developed for potential inclusion into base cases throughout 2018

- Once the ISO begins using these new methods, it may refine them as needed in 2018

- The ISO will also continue to explore the most appropriate way to consider typical unavailabilities of all resource types for their granular application in transmission planning through Q4 2018
  - This includes required data sources and probabilistic modeling of conventional thermal resource availability; hydro, wind, and PV resource availability; and load

- ISO is working with NPCC to evaluate the classification of Bulk Power System elements in light of NERC Reliability Standards
# Transmission Cost Allocation (TCA)

<table>
<thead>
<tr>
<th>Transmission Owner</th>
<th>Project</th>
<th>Pool Transmission Facilities (PTF) Cost Estimate</th>
<th>Target Date</th>
</tr>
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<tbody>
<tr>
<td>VELCO</td>
<td>PV-20 Cable Replacement</td>
<td>~$53M</td>
<td>Potential 2018 TCA Submittal</td>
</tr>
<tr>
<td>Eversource</td>
<td>Seafood Way Substation</td>
<td>~$60M</td>
<td>Q1 2018</td>
</tr>
<tr>
<td>Eversource</td>
<td>Pittsfield/Greenfield Phase 2</td>
<td>~92M</td>
<td>Potential 2018 TCA Submittal</td>
</tr>
<tr>
<td>Eversource</td>
<td>East Eagle Substation</td>
<td>~43M</td>
<td>Potential 2018 TCA Submittal</td>
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<td>United Illuminating Company</td>
<td>Baird to Housatonic River Crossing 88006A - 89006B 115 kV Line Upgrades</td>
<td>~$60M</td>
<td>Potential 2018 TCA Submittal</td>
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<tr>
<td>National Grid</td>
<td>SEMA/RI Upgrades</td>
<td>~310M</td>
<td>Potential 2018 TCA Submittal</td>
</tr>
<tr>
<td>All</td>
<td>Various Asset Condition Related Upgrades</td>
<td>~$50-$300M</td>
<td>Potential 2018 TCA Submittal</td>
</tr>
<tr>
<td>All</td>
<td>Various CIP-14 Related Upgrades</td>
<td>~$50-$100M</td>
<td>Potential 2018 TCA Submittal</td>
</tr>
</tbody>
</table>
Annual Economic Studies

• 2016 Economic Study – NEPOOL Scenario Analysis Phase I
  – The draft report was posted in July and will be discussed at the September PAC meeting
  – Phase I will be complete before Q4 2017

• 2016 Economic Study – NEPOOL Scenario Analysis Phase II
  – Work is proceeding consistent with the scope of work discussed at the PAC and is scheduled for completion by Q4 2017
    • Natural gas system capacity and energy analysis, and FCA Auction results final presentation are complete; both were discussed with the PAC
    • The scope of work for regulation, ramping, and reserves is on schedule for completion by the end of 2017. The report will be published in Q1 2018.
Annual Economic Studies, Cont.

• 2017 Economic Study will analyze similar system topologies to the 2016 Annual Economic Study Scenario 3, with similar total system emissions but a lower Relative Annual Resource Cost
  – The scope of the work, assumptions, and schedule were discussed with the PAC

• Work has commenced for the 2017 study and is expected to continue into 2018
  – The ISO is currently prioritizing the completion of the 2016 Economic Study Phase II activities
Interregional Planning

• Eastern Interconnection Planning Collaborative (EIPC)
  – Finalize production cost model data base for the Eastern Interconnection by Q4 2017
  – Coordinate with NERC and the regions on EIPC’s role in support of power system model development and analysis for the Eastern Interconnection between Q1 2018 - Q2 2019

• Northeast Coordinated System Plan (NCSP) 2017
  – The NCSP is created in partnership with NYISO and PJM. This interregional plan includes:
    • Review of respective regional needs and solutions to identify solutions for interregional transmission projects in compliance with interregional planning requirements of FERC Order 1000
    • Discussion of shared databases, needs and solutions proposed for each system, interconnection queues and other information that potentially affect interregional system performance
    • Summary of coordinated studies across ISO/RTO boundaries
  – The NCSP is expected to be complete in Q2 2018
Long-Term Forecasts (EE, PV, Load)

• The annual long-term forecast process is comprised of three separate forecasts that make projections over the 10 year planning horizon for the region and each state:
  1. Load forecast of seasonal peak demand and annual energy
  2. Energy Efficiency (EE) forecast of peak demand and energy savings stemming from state-sponsored EE programs
  3. BTM PV forecast of seasonal peak demand and energy reductions due to anticipated growth in out-of-market PV

• Three separate stakeholder processes provide opportunities for stakeholder involvement and input
  – Load forecast – Load Forecast Committee (LFC)
  – EE forecast – Energy Efficiency Forecast Working Group (EEFWG)
  – PV forecast – Distributed Generation Forecast Working Group (DGFWG)

• The annual forecast cycle begins in Q3 2017 and will be completed with the publication of the CELT report in Q2 2018
Stakeholder and Regulatory Review of Installed Capacity Requirements (ICR) / Local Sourcing Requirements (LSR)

• Discussions are underway with stakeholders on an improvement to the methodology of modeling BTM PV in the ICR calculations
  – Reviewing an hourly profile methodology that would better reflect the amount of load reduction during peak demand hours that impact system reliability
  – The ISO has been benchmarking the hourly profile methodology to illustrate the impacts on ICR for stakeholder discussion
Stakeholder and Regulatory Review of Installed Capacity Requirements (ICR) / Local Sourcing Requirements (LSR), cont.

• Significant dates for stakeholder review of FCA #12 ICR:
  – PSPC review of ISO recommendation of ICR Values – Aug 17, 2017
  – RC review/vote of ISO recommendation of ICR Values – Sep 19, 2017
  – PC review/vote of ISO recommendation of ICR Values – Oct 13, 2017
  – File with the FERC – by Nov 7, 2017

• Prepare inputs to ICR and LSR calculations for FCA #13 (2022/2023)
  – Power Supply Planning Committee review of ISO recommendation of ICR values – June/July/August 2018
  – Reliability Committee review/vote – September 2018
  – Participants Committee review/vote – October 2018
  – File with FERC – November 2018
  – FCA #13 conducted – February 2019
Modeling Capacity Zones
(FCA #13 Capacity Zone Expected Topology, Regional Transfer Limits, Identify Potential Capacity Zones, FCA #13 Zonal Requirements)

• FCA #13 Capacity Zone modeling process will begin in late 2017
  – ISO will present an overview of the expected power system topology for the 2022/2023 Capacity Commitment Period (FCA #13) in Q4 2017
  – This presentation will include a review of existing zones, discussion of relevant constraints, and factors that could “trigger” the use of these zones in FCA 13

• Regional transfer limits will be updated in Q1 2018

• Any changes or updates to Capacity Zones for FCA #13 will be identified in Q1/Q2 2018

• Zonal requirements for FCA #13 will be determined in Q2/Q3 2018
Modeling Capacity Zones

(FCA #14 Capacity Zone Expected Topology, Regional Transfer Limits, Identify Potential Capacity Zones, FCA #14 Zonal Requirements)

• FCA #14 Capacity Zone modeling process will begin in late 2018
  – ISO will present an overview of the expected power system topology for the 2023/2024 Capacity Commitment Period (FCA #14) in Q4 2018

• Regional transfer limits will be updated in Q1 2019

• Any changes or updates to Capacity Zones for FCA #14 will be identified in Q1/Q2 2019

• Zonal requirements for FCA #14 will be determined in Q2/Q3 2019
Update: FCM Auction Key Dates

• **Commitment Period #12 (2021-2022)**
  – Permanent De-list Bid and Priced Retirement De-list Bids due March 24, 2017
  – Show of Interest Window – April 14 thru April 28, 2017
  – Retirement FERC Information Filing – July 21, 2017
  – FCA FERC Informational Filing – November 7, 2017
  – Conduct Auction – February 5, 2018

• **Commitment Period #13 (2022-2023)**
  – Permanent De-list Bid and Priced Retirement De-list Bids due March 23, 2018
  – Show of Interest Window – April 16 through April 27, 2018
  – Retirement FERC Information Filing – July 20, 2018
  – FCA FERC Informational Filing – November 6, 2018
  – Conduct Auction – February 4, 2019

• **Commitment Period #14 (2023-2024)**
  – Permanent De-list Bid and Priced Retirement De-list Bids due March 22, 2019
  – Show of Interest Window – April 15 through April 26, 2019
  – Retirement FERC Information Filing – July 19, 2019
  – FCA FERC Informational Filing – November 5, 2019
  – Conduct Auction – February 3, 2020
2017/2018 Winter Reliability Program

• The Winter Reliability Program will be complete following the 2017/18 winter period

• 2017/18 Winter Reliability Program services
  – Compensation for unused oil inventory, unused liquefied natural gas (“LNG”) contract volume, and Demand Response Service
  – The ISO published the 2017/18 rates of compensation July 14th 2017

• Upcoming Winter Reliability Program deadlines include:
  • By Oct. 1: Commitments must be made
  • By Oct. 15: ISO publishes the maximum potential cost of program
  • By Dec. 1: Inventory must be stored
  • By Jan 1: Inventory used for audits must be replaced
  • By Jan 1: Duel Fuel Audits must be completed

• The ISO will provide monthly updates on the program at the relevant NEPOOL Participants Committee meetings
Operational Fuel Security Study

- ISO New England is conducting a study of fuel security challenges to the continued reliability of New England’s power system

- The study is examining more than twenty scenarios of generating resource and fuel-mix combinations and will quantify each scenario’s fuel security risk
  - For the purposes of this study, risk is assessed as the number and duration of energy shortfalls that would require implementation of emergency procedures to maintain reliability during the entire winter period in 2025

- The initial results will be presented to regional stakeholders for discussion and input beginning in October 2017

- Following stakeholder discussion and refinement of the study, the ISO will work with stakeholders to determine whether further operational or market measures will be needed to address the fuel security risk (see slide 51)
Black Start Review

- The ISO compensates certain resources that are capable of providing black start services
- The ISO is reviewing the current compensation mechanisms
- If, after assessment, the ISO determines any changes are needed, the earliest start of the stakeholder process would be Q2 2018
Critical Infrastructure Protection (CIP) 
Interconnection Reliability Operating Limit (IROL) 
Compensation Review

• Generators critical to derivation of an Interconnection Reliability Operating Limit (IROL) may need to make upgrades in order to meet NERC criteria under the Critical Infrastructure Protection (CIP) Standard

• The ISO is reviewing compensation mechanisms for the upgrades

• If, after assessment, the ISO determines any changes are needed, the earliest start of the stakeholder process would be Q2 2018
Generator Interconnection Studies
New Generation Update as of August 1, 2017

• In total, 91 generation projects are currently being tracked by the ISO totaling approximately 13,500 MW
  – 17 in scoping stage
  – 12 in feasibility study (FS)
  – 23 in system impact study (SIS)/optional interconnection study
  – 0 in facilities study
  – 18 negotiating interconnection agreements (IA)
  – 17 with interconnection agreements
  – 4 distribution interconnections

Note: Additionally, there are 9 Elective Transmission Upgrades (ETU) in the in the SIS phase, 4 in the FS phase, 6 in Scoping, and 4 negotiating IAs

Note: Implementation of new clustering rules scheduled to take place in late 2017 and throughout 2018
NERC/FERC Compliance/Cyber Security

• Ensure compliance with new and existing NERC and FERC orders
  – The ISO plans to fully staff the new cyber security operations group to enhance compliance monitoring
  – Work with NERC on its new Reliability Assurance Initiative
  – Continued interaction with Participants on matters relating to NPCC's administration and auditing of NERC Standards

• Enhance existing tools, processes, and controls to provide better protection against current and emerging cyber security threats

• In addition to a NERC/NPCC on-site audit of CIP Version 5 sometime in 2018, the ISO plans to implement various cyber security related infrastructure improvements related to identity and access management
NERC/FERC Compliance/Cyber Security

• ISO is continuing to address different planning, modeling, relay protection, and CIP standards
  – Assess new dynamic operating characteristic information provided by generation owners as model updates are provided
  – Continue assessment of appropriate dynamic load models and address any newly identified system concerns
  – Implement standard for geo-magnetic disturbances
  – Prepare for new standards mitigating supply chain risks
  – Assess the impact of continued penetration of distributed energy resources
  – Assess NERC’s study on potential single point of failure on natural gas infrastructure
  – Develop, procure, and implement a New England wide transmission protection database
NERC/FERC Compliance/Cyber Security

• NERC Grid Security Exercise
  – NERC will be conducting its fourth exercise (GridEx IV) on cyber and physical security in November 2017
  – The exercise brings together NERC, the industry, and government agencies, as well as participants from Canada and Mexico
    • Exercise the readiness of the electricity industry to respond to a security incident
    • Review existing command, control, and communication plans and tools
    • Identify potential improvements in cyber and physical security plans, programs, and responder skills
    • Coordinate with federal, state, and local law enforcement agencies
  – ISO will share relevant results with stakeholders following issuance of NERC report in Q2 2018
Regional System Plan (RSP)

• The RSP is a comprehensive planning report on system needs and the resource and transmission facilities needed to maintain the reliability of New England’s power system over a 10-year horizon, while also accounting for market efficiencies, economic, and environmental considerations
  – RSP will contain project list updates and asset condition list updates

• The 2017 RSP expected to be complete in Q4 2017
• The 2019 RSP expected to be complete in Q4 2019
## Markets Related Activities

<table>
<thead>
<tr>
<th>2017</th>
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<tr>
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### Integrating Markets and Public Policy (IMAPP) Related

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- **Competitive Auctions with Sponsored Policy Resources (CASPR)** (slide 33)
- **CASPR Conforming Changes** (slide 34)
- **Discussions on IMAPP "Achieve" Solutions** (slide 35)

### Capacity Market

- **Zonal Demand Curves: CSO Transactions using MRI Demand Curves** (slide 37)
- **FCM Enhancements Phase II** (slide 38)
- **Repowering Construct** (slide 39)
- **Dynamic De-list Bid Threshold** (slide 40)
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- **FCA #13 CONE Adjustment** (slide 43)
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### Energy and Reserve Markets

- **Real-Time Reserve Designation & Settlement Rules** (slide 46)
- **Multi-Period Ramp Pricing Technical Sessions** (slide 47)
- **Enhanced Storage Participation** (slide 48)
- **Day-Ahead Co-optimization Technical Sessions** (slide 49)

### Other Market Related Items

- **Potential Fuel Security Solutions** (slide 51)
- **FERC Orders and NOPRs** (slide 52)
MARKET RELATED ACTIVITIES

Integrating Markets and Public Policy (IMAPP) Related
Competitive Auctions with Sponsored Policy Resources (CASPR)

• The region has been discussing approaches to accommodate certain resources sponsored by public entities to meet various policy priorities

• The ISO’s CASPR proposal is designed to maintain competitively-based capacity price signals while, over time, accommodating the entry of new resources sponsored by public entities into the FCM

• The stakeholder process is underway and is expected to conclude in Q4 2017
  – Implementation is targeted for Q4 2018
Competitive Auctions with Sponsored Policy Resources (CASPR): Conforming Changes

- In 2018, the ISO will review the CASPR proposal during the implementation phase and determine if any additional conforming changes are required
- If necessary, the stakeholder process is expected to start no earlier than Q3 2018
  - Implementation is targeted for FCA 13
Discussions on Integrating Markets and Public Policy (IMAPP) “Achieve” Solutions

- The ISO will continue to attend and participate in meetings to develop potential “achieve” solutions that maintain transparent and competitive markets and incorporate the states’ initiatives for clean energy

- With work underway on CASPR, the ISO is focusing on the “accommodate” aspect of this initiative

- The ISO will remain active in discussions of proposals provided by NEPOOL Participants and will provide feedback as requested
MARKET RELATED ACTIVITIES

Capacity Market Related
Zonal Demand Curves: CSO Transactions using MRI Demand Curves

• Under the MRI demand curves, the current practice of trading Capacity Supply Obligation (CSO) across capacity zones using a CSO bilateral transaction can no longer be supported
• The ISO has developed a replacement mechanism called Annual Reconfiguration Transactions (ART) to replace annual CSO bilateral transactions
• The stakeholder process is underway and expected to conclude in Q4 2017
  – Implementation of the MRI demand curves in the annual reconfiguration auction (ARA) is scheduled for ARA1 for CCP11 in June 2018
  – Implementation of the ART is targeted for no earlier than ARA1 for CCP12 in June 2019
FCM Enhancements Phase II

- Phase II of FCM Enhancements includes:
  - Qualification timeline changes
  - Commercial determinations for intermittent power resources and energy efficiency resources
  - Other FCM enhancements including market rule cleanup changes

- The stakeholder process is expected to start in Q3 2017 and conclude in Q4 2017
  - Implementation is targeted for Q2 2018 and Q2 2020
Repowering Construct

- NEPOOL is reviewing a Participant proposal that allows the existing resource to continue to provide CSO MWs for a period of time before the newly repowered resource comes online
- The ISO is working to assist the Participant proposal
- The stakeholder process is underway is expected to be completed in Q4 2017
Dynamic De-list Bid Threshold

• The Tariff requires an update of the Dynamic De-list Bid Threshold every three years

• An analysis of the Dynamic De-list Bid Threshold will be performed and a recommended value will be proposed

• The stakeholder process is scheduled to start in Q3 2017 and conclude in Q4 2017
  – Implementation is targeted for Q1 2018, coinciding with the retirement delist bid deadline for FCA13
FCM Pay for Performance (PFP): Conforming Changes

- The FCM PFP design links capacity revenues to resource performance during Capacity Scarcity Conditions beginning with the CCP9 in June 2018

- The ISO has identified a number of conforming changes as part of the implementation review of the design that will require modifications to the Tariff and Manuals

- The stakeholder process is expected to start in Q4 2017 and conclude in Q1 2018
  - Implementation is targeted for Q2 2018 (CCP9)
Zonal Demand Curves: FCM Cost Allocation

- For CCP 11 (2020-2021), the ISO cleared the FCA using demand curves that account for the marginal reliability impact of procuring capacity in constrained zones (MRI demand curves)
- The ISO is reviewing how the costs are allocated to locations under the MRI demand curves
- If changes are necessary, the stakeholder process is expected to start no earlier than Q1 2018
  - Implementation is targeted for Q2 2020 (CCP11)
CONE and ORTP Adjustments and Recalculation

• Cost Of New Entry (CONE), Net CONE, and Offer Review Trigger Prices (ORTP) for FCA 13 and FCA 14 will be adjusted pursuant to Market Rule 1 III.A.21.1.2 (e)

• The adjusted values for FCA 13 and FCA 14 will be provided in Q1 2018 and Q1 2019, respectively

• CONE, Net CONE, and ORTP for FCA 15 will be recalculated in their entirety as required by Market Rule 1
  – The stakeholder process is expected to start in Q2 2019 and conclude by Q4 2019
Delayed Commercial Operation of New Resources

- The ISO is reviewing the current rules around the treatment of new capacity resources that do not achieve their planned commercial operation date

- If changes are necessary, the stakeholder process is expected to start no earlier than Q2 2018
  - Implementation would be dependent upon scope of any changes
MARKET RELATED ACTIVITIES

Energy and Reserve Market Related
Real-Time Reserve Designation & Settlement Rules

- With the Subhourly Settlement implementation, reserve compensation is based upon five-minute real-time reserve designations
- The ISO, therefore, is reviewing its real-time reserve designation and settlement constructs
- The stakeholder process is expected to start in September 2017 and conclude by Q1 2018
  - Implementation is targeted for Q2 2018
Multi-Period Ramp Pricing Technical Sessions

• The ISO is planning to assess the potential development of a new, transparent pricing system for the costs incurred when the system is re-dispatched in advance of a sustained load ramp

• The ISO will begin holding technical sessions in Q3 2017 on the evolving ramping needs of ISO-NE, examples of ISO-NE’s ramping process, and ramping-related market designs of other regions

• Additional sessions held through Q1 2018, will focus on procurement and pricing of ramping capability from the perspectives of reliability and economics

• After these sessions, the ISO will have future stakeholder discussions if changes will be proposed
Enhanced Storage Participation

- FERC accepted changes that enable Energy Storage Devices (ESD) to participate in the regulation market as an Alternative Technology Regulation Resource (ATRR) and in the energy and reserve markets as a dispatchable generator and Dispatchable Asset Related Demand (DARD)
  - This change is effective in December 2018

- The ISO is evaluating the applicability of extending current DARD Pump treatment to other storage devices and whether additional conforming changes would be necessary to extend that model

- The stakeholder process is expected from Q1 2018 - Q2 2018
  - Implementation is targeted for Q4 2018
Day-Ahead Co-optimization Technical Sessions

• The ISO will evaluate design changes to co-optimize energy and reserves in the day-ahead market
  – Allowing suppliers to submit financially binding offers for reserves on a day-ahead basis, in addition to submitting their offers for energy, will improve price formation by signaling the costs suppliers must incur to provide reliable operating reserves

• The ISO will hold technical sessions between Q3 2018 and Q1 2019 to share information with participants

• The ISO will look for further stakeholder feedback on next steps after the sessions are completed
OTHER MARKET RELATED ACTIVITIES
Potential Fuel Security Solutions

• The ISO is conducting an Operational Fuel Security Study to quantify the operational risks to the reliability of New England’s power system (see slide 23)

• If, after the Operational Fuel Security Study is complete, the analysis reveals risks that require action, the ISO will commence a stakeholder process in Q2 2018 to receive, discuss, and prioritize possible market-based solutions

• The ISO will assess these solutions and anticipates stakeholder discussions through Q1 2019
FERC Orders and NOPRs

- If FERC issues Orders and Notices of Proposed Rulemaking (NOPRs), or ISO has to respond to filings, it may impact the ISO’s plans on other identified priorities.

- Timing of the stakeholder process is dependent on when Orders and NOPRs are issued by the FERC and the compliance schedule outlined by FERC.
## Capital Projects

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<tr>
<td>Desktop Segregation Project: Cyber Security (slide 55)</td>
<td>Price Responsive Demand (PRD) (slide 56)</td>
<td>Forward Capacity Market Improvements (slide 57)</td>
</tr>
</tbody>
</table>
CAPITAL PROJECTS
Desktop Segregation Project: Cyber Security

- The ISO will design and implement an enhanced architecture to segregate network access.
- Best practices have developed around restricting access to networked services and systems based on job requirements.
- The implementation efforts will include: assessing risks, developing procedures, hardware and software changes, and new processes.
- This project is targeted for completion in Q4 2017.
Price Responsive Demand (PRD)

- The ISO is fully integrating demand response resources into ISO markets, comparable to other supply resources, starting June 1, 2018
- Implementation for this project includes major software alterations
  - To enable demand response resources participate fully, comprehensive updates to operational and settlement software must be developed and tested
- This project is targeted for completion in Q2 2018
Forward Capacity Market Improvements

• The FCM Improvements project will introduce sloped zonal demand curves into the Annual Reconfiguration Auctions effective with the eleventh Capacity Commitment Period

• This project is targeted for completion in Q2 2018
FCM Pay for Performance

- The Pay For Performance design links capacity revenues to resource performance during reserve deficiencies.
- Implementation includes building software that determines if a Capacity Scarcity Condition has been triggered in each reserve zone, for TMOR and TMNSR, and in each 5-minute interval.
- This project is targeted for completion in Q2 2018.
Balance of Planning Period (BoPP): Financial Assurance

• This project aims to implement the new monthly Financial Transmission Rights (FTR) auction and the FTR Financial Assurance methodology

• Having withdrawn its previous filing of a financial assurance methodology for the FTR/BoPP auctions in response to stakeholder concerns, ISO-NE and stakeholders must revisit that methodology, file it again with FERC, and await its acceptance

• This project is currently targeted for completion in Q3 2018
Identity and Access Management

- The Access Rights and employee applications perform critical Identity and Access Management functions of enabling workforce members to request, approve, and implement access to IT assets (servers, systems, shared drives, badged physical access, etc.)

- New hardware, software, and system functionalities will be set up to further protect the ISO’s IT assets and comply with NERC CIP version 5 requirements

- This project is targeted for completion in Q3 2018
Internal Market Monitoring Data Analysis

• The Internal Market Monitor (IMM) requires access to a large variety of market data for both the current and historical time periods

• This will allow the IMM group to better analyze data across multiple markets and multiple market products; the end result will be the implementation of a new IMM Market Analysis system

• The targeted completion date for phase I of this project is Q2 2018

• The targeted completion date for phase II of this project is Q4 2018
Competitive Auctions with Sponsored Policy Resources (CASPR)

- This project is intended to implement the CASPR market design (see slide 33) that will be filed with FERC in time for FCA 13
- Currently, the work is projected to be completed by Q4 2018
Operational Load Forecast: PV Integration

• The output of BTM PV resources are not visible to ISO-NE which can pose significant forecasting challenges

• This project will incorporate the effects of BTM PV generation on net system load into the Day-Ahead and Seven-Day Load Forecasts

• This project is targeted for completion in Q4 2018
Energy Management Platform 3.2 Upgrade and Customs Reduction

• The ISO’s Energy Management System (EMS) is based on GE’s suite of Energy Management Platform (EMP) applications, which has newly released version 3.2. In order for GE to provide EMP support, the ISO must upgrade to version 3.2 before 2020.
  – When GE upgrades its software, a significant effort is needed to port the ISO’s EMP customizations to the upgraded software. During this upgrade, the ISO will also seek to eliminate some of the ISO customizations to simplify the software upgrade.

• The targeted completion date for this project is Q4 2018
Storage Device Alternatives

• This project seeks to improve emerging grid-sized storage participation in the markets for capacity, energy, and ancillary services (see slide 48) and strengthen the ISO’s operational awareness through enhanced software to better monitor and dispatch Energy Storage Devices.

• This project is targeted for completion in Q4 2018.
nGEM Software Development

• GE Grid Solutions is working on its next GEneration Market Management System (nGEM) software

• The nGEM Software Development project, a multi-year project, involves the re-architecture of GE’s Generation Market Management System

• This will be completed in two phases
  – Phase 1 will focus on enhanced data transfer technology and software upgrades, in addition to Day-Ahead and Real-Time market clearing engine enhancements
  – Phase 2 will focus on bidding micro services
  – Some of the ISOs are funding a portion of this development project as it offers several benefits in terms of product development and software licenses

• This project is targeted for completion in Q2 2019
CIMNET Simultaneous Feasibility Test with Data Transfer Enhancements

• The CIMNET Simultaneous Feasibility Test with Data Transfer Enhancements project will deploy into production the upgraded software that will be developed as part of Phase I of the nGEM Software Development project

• This project is targeted for completion in Q4 2018
2018 / 2019 Issue Resolution

• The 2018 / 2019 Issue Resolution project will enhance various software systems
  – The software changes span a range of functionality including user interface improvements, internal reporting improvements, enterprise applications, and settlement calculation changes

• The targeted completion date for these projects are Q4 2018 and Q4 2019 respectively
Forward Capacity Auction #13

- Incorporate necessary software and hardware enhancements including those that might be related to the integration of CASPR
- This project is targeted for completion in Q2 2019
ACTIVITY DRIVERS
# Planning/ Operations Activity Drivers

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<th>Market Efficiency Impact</th>
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<td>ISO Initiative</td>
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<td>Medium</td>
</tr>
<tr>
<td>Order 1000 Implementation</td>
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<tr>
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<tr>
<td>Transmission Cost Allocation</td>
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Planning/ Operations Activity Drivers, cont.

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<th>Activity</th>
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</tr>
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<tbody>
<tr>
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<tbody>
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<td>Generator Interconnection Studies</td>
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<tr>
<td>Discussions on IMAPP “Achieve” Solutions</td>
<td>Public Policy and Market Participants</td>
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<td>High</td>
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<td>Zonal Demand Curves: CSO Transactions using MRI Demand Curves</td>
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<tr>
<td>FCM Enhancements Phase II</td>
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<td>FCM PFP Conforming Changes</td>
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<td>Zonal Demand Curve: FCM Cost Allocation</td>
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<tr>
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<td>Enhanced Storage Participation</td>
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# Capital Project Activity Drivers

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<th>Estimated 2018 Implementation Costs</th>
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<tbody>
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<td>EMP 3.2 Upgrade and Customs Reduction</td>
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<tr>
<td>Storage Device Alternatives</td>
<td>ISO Initiative</td>
<td>Medium</td>
<td>Medium</td>
<td>1.8M</td>
</tr>
<tr>
<td>CIMNET Simultaneous Feasibility Test</td>
<td>ISO Initiative</td>
<td>Medium</td>
<td>Medium</td>
<td>2.0M</td>
</tr>
<tr>
<td>nGEM Software Development</td>
<td>Technology Upgrade</td>
<td>Medium</td>
<td>Medium</td>
<td>1.8M</td>
</tr>
<tr>
<td>2018 Issue Resolution</td>
<td>ISO Initiative</td>
<td>Medium</td>
<td>Medium</td>
<td>1.5M</td>
</tr>
<tr>
<td>2019 Issue Resolution</td>
<td>ISO Initiative</td>
<td>Medium</td>
<td>Medium</td>
<td>N/A</td>
</tr>
<tr>
<td>FCA #13</td>
<td>Tariff Compliance</td>
<td>High</td>
<td>High</td>
<td>2.0M</td>
</tr>
</tbody>
</table>
Capital Projects

• Each quarter, the ISO discusses changes and updates to its capital budget with stakeholders and files a quarterly capital projects report with the FERC
  – The quarterly report captures any changes in the cost of a project
  – The quarterly report also notes projects that are completed and new projects that are chartered
  – The most accurate quarterly costs are reflected in these quarterly reports
  – Please note that the resource estimates and costs contained in this presentation are only approximations, likely to change through the course of the year based on scope, schedule and other emerging priorities
Resource Allocation Estimates

• The next two slides illustrate the relative resource allocation across activities contained in the work plan
  – These resources are only estimates and actual allocation of resources across all activities changes frequently based on scope, schedule and emerging priorities
  – Costs associated with generator interconnection studies are mostly reimbursed by the study owner
Estimated Resource Allocation to Operating Activities

### Estimated Resource Allocation (Annual FTE's)

- **Operational Load Forecast: PV Integration**: 6%
- **Order 1000 / Transmission Planning**: 15%
- **Transmission Cost Allocation**: 2%
- **Annual Economic Studies**: 2%
- **Long-Term Forecasts (PV, EE, Load)**: 1%
- **Review of ICR/LSR**: 2%
- **FCA Auctions and Administration**: 2%
- **2017/18 Winter Program**: 12%
- **Operational Fuel Security Study**: 16%
- **Black Start / CIP IROL Review**: 5%
- **Generator Interconnection Studies**: 5%
- **NERC/Cyber Security**: 3%
- **CASPR**: 2%
- **Other FCM Initiatives**: 3%
- **Ramp Pricing/DA Co-optimization**: 3%
- **Other Market Assessments**: 5%
Estimated Resource Allocation to Capital Projects

Estimated Resource Allocation (Annual FTE's)

- Price Responsive Demand
- Forward Capacity Market Improvements
- FCM Pay for Performance
- Balance of Planning Period
- FCA 13
- Identity/Access Management
- IMM Data Analysis
- CASPR
- Operational LF: PV Integration
- Energy Management Platform Upgrade
- Storage Device Alternatives
- SFT with Data Transfer Enhancements
- nGEM Software Development
- 2018/2019 Issue Resolution Project
ISO New England
Proposed 2018 Operating and Capital Budgets

NEPOOL Participants Committee Meeting

Robert Ludlow
VP, CHIEF FINANCIAL & COMPLIANCE OFFICER
INTRODUCTION AND OVERVIEW
2018 Budget Review Process

• At both the June 4, 2017 meeting with the New England Conference of Public Utilities Commissioners (NECPUC), and the June 27, 2017 NEPOOL Summer Meeting, management presented and reviewed the preliminary operating budgets for 2018 and 2019 and the preliminary capital budget for 2018.

• The proposed 2018 budget in this presentation is generally in line with the services and funding included in the preliminary budget presented in June.
2018 Budget Review Process (cont.)

• The ISO reviewed the 2018 proposed Operating and Capital Budgets:
  – With the NEPOOL Budget & Finance Subcommittee on August 11th. For further detail on ISO-NE’s 2018 budget, please see the presentation provided to the NEPOOL Budget and Finance Subcommittee at the August 11, 2017 meeting. The presentation can be found at:
  – With the State Agencies on August 15th.
    • State Agencies submitted questions on ISO-NE’s proposed budget on August 22nd.
    • ISO-NE responded to State Agencies’ questions on August 28th. The State Agencies questions and ISO-NE’s responses can be found at:
    • State Agencies submitted comments regarding the proposed budget on September 6th.
    • The ISO Board of Directors will review the budgets, stakeholder feedback, and State Agencies comments on September 14th.
    • ISO-NE responses to State Agencies’ comments and proposed adjustments are due on or about September 21st.
2018 Budget Review Process (cont.)

• The ISO will conduct additional meetings as requested.

• NPC will vote on the ISO-NE 2018 Budgets on October 13th.

• The ISO Board of Directors will vote on the Budgets after the NPC meeting.

• The ISO will file the 2018 Budgets with FERC on or about October 17th.
Overview of 2018 Operating Budget

• The 2018 Operating Budget includes:
  – Cyber Security cost increases.
    • Five new full-time equivalent (FTE) employees and four existing FTEs reallocated to address the significant requirements to comply with NERC Critical Infrastructure Protection (CIP) Version 5 and protect against continuing cyber threats.
  – Compensation/medical and defined contribution pension plan increases.
  – Results of priorities and work plan discussions with stakeholders, including the implementation of Price Responsive Demand, wholesale market design changes that include Competitive Auctions with Sponsored Policy Resources, and potential solutions to mitigate fuel security.
  – On-going support/inflationary increases including Computer Services and Systems Support.
  – Efficiencies and Reductions (e.g., one-time studies, reallocation of employees, non-recurring costs).
Overview of 2018 Operating Budget (cont.)

• The proposed 2018 operating budget, including depreciation, excluding the true-up for past years, represents an increase of 1.5% (or $2.9 million) over the 2017 budget.

• Taking into account the true-up adjustment the 2018 estimated revenue requirement is a 1.9% increase over 2017.

• The budgets reflect the ISO’s recognition of the importance of containing costs while continuing to provide excellent service.
Future Operating Budgets, Initiatives, and Risks

• In developing the 2018 budgets, management contained costs and kept the budget increase to a minimum and in line with the preliminary budget presented in June. This was accomplished through:

  – Reallocating resources to newly established and on-going Cyber Security requirements, for the CASPR initiative, and for implementation and enhancement of market changes for PRD and FCM (including Pay for Performance).
  – Reductions of non-recurring consultant support or work absorbed by internal staff including Information Technology, Market Monitoring, System Planning, and Human Resources, and reductions in corporate training programs.
  – Reductions in salaries as a result of retirements and staff turnover that have occurred over the past several years.

• Retirement planning and knowledge transfer processes have enabled the ISO to hire more entry level employees and save the expense of filling staffing gaps with higher priced consultants.

  – Depreciation expense reduction due to a number of larger projects and market enhancements becoming fully depreciated in 2017.
Future Operating Budgets, Initiatives, and Risks (cont.)

• Material risks for future budget cycles include:
  – Continued Cyber Security threats and issues, including implementing the FERC supply chain standards to minimize threats to our systems (which may require renegotiation of vendor contracts to incorporate cyber safeguards), and increased requirements when NERC CIP 13 becomes effective. This will likely cause continued cost increases beyond 2018;
  – Continued Computer Service costs for upkeep and maintenance of significant market and grid operation enhancements made over the past several years and future market enhancements (i.e., PRD and Pay For Performance);
  – Additional work related to fuel security issues; and
  – Litigation risks.

• Management realizes the need to balance regulatory requirements, stakeholder needs, and being pro-active in addressing Cyber Security threats while limiting budget increases to what is necessary. Accordingly, management has:
  – Focused on how best to reallocate resources to emerging priorities and to drive additional efficiency in the organization.
  – Selected among competing priorities given the resources required, particularly in IT, to implement and maintain program changes.
SUMMARY BUDGET INFORMATION
## Summary Budget Information

<table>
<thead>
<tr>
<th>(Budget Amounts are in Millions)</th>
<th>2018</th>
<th>Change</th>
<th>2017</th>
<th>Change</th>
<th>2016</th>
<th>Change</th>
<th>2015</th>
<th>Change</th>
<th>2014</th>
<th>Change</th>
<th>2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operating Budget Before Depreciation</td>
<td>$164.6</td>
<td>3.5%</td>
<td>$158.9</td>
<td>4.5%</td>
<td>$152.2</td>
<td>3.8%</td>
<td>$146.6</td>
<td>4.0%</td>
<td>$140.9</td>
<td>4.0%</td>
<td>$135.5</td>
</tr>
<tr>
<td>Capital Budget</td>
<td>28.0</td>
<td>0.0%</td>
<td>28.0</td>
<td>3.7%</td>
<td>27.0</td>
<td>(3.6%)</td>
<td>28.0</td>
<td>0.0%</td>
<td>28.0</td>
<td>(4.4%)</td>
<td>29.3</td>
</tr>
<tr>
<td>Total Cash Budget</td>
<td>$192.6</td>
<td>3.0%</td>
<td>$186.9</td>
<td>4.4%</td>
<td>$179.2</td>
<td>2.6%</td>
<td>$174.6</td>
<td>3.4%</td>
<td>$168.9</td>
<td>2.5%</td>
<td>$164.8</td>
</tr>
<tr>
<td>Operating Budget Before Depreciation</td>
<td>$164.6</td>
<td>3.5%</td>
<td>$158.9</td>
<td>4.5%</td>
<td>$152.2</td>
<td>3.8%</td>
<td>$146.6</td>
<td>4.0%</td>
<td>$140.9</td>
<td>4.0%</td>
<td>$135.5</td>
</tr>
<tr>
<td>Depreciation</td>
<td>31.0</td>
<td>(8.1%)</td>
<td>33.7</td>
<td>2.1%</td>
<td>33.0</td>
<td>4.1%</td>
<td>31.7</td>
<td>11.6%</td>
<td>28.4</td>
<td>(0.4%)</td>
<td>28.5</td>
</tr>
<tr>
<td>Revenue Requirement Before True-up</td>
<td>195.6</td>
<td>1.5%</td>
<td>192.7</td>
<td>4.1%</td>
<td>185.2</td>
<td>3.8%</td>
<td>178.3</td>
<td>5.3%</td>
<td>169.3</td>
<td>3.2%</td>
<td>164.0</td>
</tr>
<tr>
<td>True up</td>
<td>0.4</td>
<td>(0.4)</td>
<td>0.6</td>
<td>(0.6)</td>
<td>0.6</td>
<td>(0.6)</td>
<td>0.6</td>
<td>(0.6)</td>
<td>0.6</td>
<td>(0.6)</td>
<td>0.9</td>
</tr>
<tr>
<td>Revenue Requirement</td>
<td>$196.0</td>
<td>1.9%</td>
<td>$192.3</td>
<td>4.2%</td>
<td>$184.6</td>
<td>9.5%</td>
<td>$168.5</td>
<td>(1.6%)</td>
<td>$171.2</td>
<td>3.8%</td>
<td>$164.9</td>
</tr>
<tr>
<td>Forecast – TWhs (1)</td>
<td>142.1</td>
<td>1.2%</td>
<td>140.3</td>
<td>0.5%</td>
<td>139.6</td>
<td>(0.6%)</td>
<td>140.4</td>
<td>1.1%</td>
<td>138.9</td>
<td>0.0%</td>
<td>138.9</td>
</tr>
<tr>
<td>$/KWh Rate</td>
<td>$0.00138</td>
<td>0.7%</td>
<td>$0.00137</td>
<td>3.6%</td>
<td>$0.00132</td>
<td>10.2%</td>
<td>$0.00120</td>
<td>(2.6%)</td>
<td>$0.00123</td>
<td>3.8%</td>
<td>$0.00119</td>
</tr>
<tr>
<td>Average Monthly Consumer Cost (2)</td>
<td>$1.03</td>
<td>$1.03</td>
<td>$0.99</td>
<td>$0.90</td>
<td>$0.92</td>
<td>$0.89</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

(1) 2018 Forecast based on May 2017 CELT Report. All other years based on CELT Report Forecast Data for the applicable year, which can be found on www.iso-ne.com. Amounts shown include Photovoltaic (PV) and Passive Demand Response (PDR). Excluding PV and PDR amounts are (in TWhs) 126.4 (’18), 128.4 (’17), 128.6 (’16), 130.5 (’15), 131.0 (’14), and 132.2 (’13).

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

Note: Throughout the presentation some schedules may be inconsistent due to rounding.
### New England Wholesale Electricity Costs\(^{(a)}\)

<table>
<thead>
<tr>
<th></th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016(^{(b)})</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$ Mil.</td>
<td>¢/kWh</td>
<td>$ Mil.</td>
<td>¢/kWh</td>
<td>$ Mil.</td>
</tr>
<tr>
<td><strong>Wholesale Market Costs</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Energy (LMPs)(^{(c)})</td>
<td>$5,193</td>
<td>3.9</td>
<td>$8,009</td>
<td>6.0</td>
<td>$9,079</td>
</tr>
<tr>
<td>Ancillaries(^{(d)})</td>
<td>$56</td>
<td>0.0</td>
<td>$152</td>
<td>0.1</td>
<td>$331</td>
</tr>
<tr>
<td>Capacity(^{(e)})</td>
<td>$1,182</td>
<td>0.9</td>
<td>$1,039</td>
<td>0.8</td>
<td>$1,056</td>
</tr>
<tr>
<td><strong>Subtotal</strong></td>
<td>$6,431</td>
<td>4.8</td>
<td>$9,200</td>
<td>6.9</td>
<td>$10,466</td>
</tr>
<tr>
<td><strong>Transmission Charges</strong>(^{(f)})</td>
<td>$1,494</td>
<td>1.1</td>
<td>$1,823</td>
<td>1.4</td>
<td>$1,822</td>
</tr>
<tr>
<td>RTO Costs(^{(g)})</td>
<td>$139</td>
<td>0.1</td>
<td>$167</td>
<td>0.1</td>
<td>$165</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$8,064</td>
<td>6.0</td>
<td>$11,190</td>
<td>8.4</td>
<td>$12,453</td>
</tr>
</tbody>
</table>

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

\(^{(b)}\) The wholesale values for 2016 are subject to requested billing adjustments.

\(^{(c)}\) Energy values are derived from wholesale market pricing, and represent the results of the Day-Ahead Energy Market plus deviations from the Day-Ahead Energy Market reflected in the Real-Time Energy Market.

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

\(^{(e)}\) Capacity charges are those associated with the transitional Installed Capacity (ICAP) Market through May 2010 and the Forward Capacity Market (FCM) from June 2010 forward.

\(^{(f)}\) Transmission charges reflect the collection of transmission owners’ revenue requirements and tariff-based reliability services, including black-start capability and voltage support. FCM reliability totals are not included in this value. In 2016, the cost of payments made to these generators for reliability services under the ISO’s tariff was $37.5 million.

\(^{(g)}\) RTO costs are the costs to run and operate ISO New England and are based on actual collections, as determined under Section IV of the ISO New England Inc. Transmission, Markets, and Services Tariff.
New England Retail Electricity Rates: Winter Snapshot

Average retail price of electricity to residential customers for January 2013, January 2014, January 2015, January 2016 and January 2017 (monthly averages)

<table>
<thead>
<tr>
<th>State</th>
<th>January 2013 (cents/kWh)</th>
<th>January 2014 (cents/kWh)</th>
<th>January 2015 (cents/kWh)</th>
<th>January 2016 (cents/kWh)</th>
<th>January 2017 (cents/kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Connecticut</td>
<td>17.05</td>
<td>18.29</td>
<td>21.00</td>
<td>19.85</td>
<td>19.28</td>
</tr>
<tr>
<td>Maine</td>
<td>14.49</td>
<td>14.45</td>
<td>15.62</td>
<td>15.28</td>
<td>15.95</td>
</tr>
<tr>
<td>Massachusetts</td>
<td>14.28</td>
<td>16.83</td>
<td>20.80</td>
<td>19.35</td>
<td>19.59</td>
</tr>
<tr>
<td>New Hampshire</td>
<td>16.01</td>
<td>16.54</td>
<td>19.15</td>
<td>18.00</td>
<td>18.48</td>
</tr>
<tr>
<td>Rhode Island</td>
<td>14.80</td>
<td>17.56*</td>
<td>17.72</td>
<td>18.40</td>
<td>18.98</td>
</tr>
<tr>
<td>Vermont</td>
<td>16.50</td>
<td>16.94</td>
<td>16.48</td>
<td>16.62</td>
<td>17.05</td>
</tr>
</tbody>
</table>

Source: U.S. Energy Information Administration (EIA) Electric Power Monthly

- The January 2014 monthly average retail price of electricity for Rhode Island was replaced with the 2014 annual average due to a discrepancy in the January 2014 monthly average reported by EIA.
# New England Retail Electricity Rates: Summer Snapshot

*Average retail price of electricity to residential customers for July 2012, July 2013, July 2014, July 2015 and July 2016 (monthly averages)*

<table>
<thead>
<tr>
<th>State</th>
<th>July 2012 (cents/kWh)</th>
<th>July 2013 (cents/kWh)</th>
<th>July 2014 (cents/kWh)</th>
<th>July 2015 (cents/kWh)</th>
<th>July 2016 (cents/kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Connecticut</td>
<td>17.10</td>
<td>17.31</td>
<td>19.46</td>
<td>20.40</td>
<td>19.78</td>
</tr>
<tr>
<td>Maine</td>
<td>14.70</td>
<td>14.26</td>
<td>15.31</td>
<td>15.42</td>
<td>15.87</td>
</tr>
<tr>
<td>Massachusetts</td>
<td>14.61</td>
<td>15.12</td>
<td>16.29</td>
<td>17.87</td>
<td>18.19</td>
</tr>
<tr>
<td>New Hampshire</td>
<td>15.84</td>
<td>16.11</td>
<td>17.23</td>
<td>17.76</td>
<td>18.00</td>
</tr>
<tr>
<td>Rhode Island</td>
<td>13.89</td>
<td>13.31</td>
<td>15.85</td>
<td>17.59</td>
<td>17.11</td>
</tr>
<tr>
<td>Vermont</td>
<td>16.93</td>
<td>17.23</td>
<td>17.93</td>
<td>17.07</td>
<td>17.29</td>
</tr>
</tbody>
</table>

*Source:* U.S. Energy Information Administration (EIA) *Electric Power Monthly*
Note: Items in yellow above represent the estimate that was included in the 2018 preliminary budget presented in June 2017.
Represents cumulative annual Operating Budget costs for Cyber Security that have been added in the 2014 through 2018 budgets and are ongoing and included in the 2018 Proposed budget. An additional $0.7 million of non-recurring Cyber Security operating costs were incurred from 2014 through 2017 that are not included above.
CAPITAL BUDGET
## Capital Budget

### 2018 Expenditures

<table>
<thead>
<tr>
<th>Major Projects in Development</th>
<th>2018 Costs</th>
<th>Total Project Costs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Price Responsive Demand</td>
<td>$2.1M</td>
<td>$9.6M</td>
</tr>
<tr>
<td>Forward Capacity Market - Pay for Performance</td>
<td>$0.6M</td>
<td>$2.5M</td>
</tr>
<tr>
<td>Internal Market Monitoring Data Analysis Phase I</td>
<td>$0.4M</td>
<td>$1.3M</td>
</tr>
</tbody>
</table>

### In Planning/Conceptual Design

<table>
<thead>
<tr>
<th>Project Description</th>
<th>2018 Costs</th>
<th>Total Project Costs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Competitive Auctions with Sponsored Policy Resources (&quot;CASPR&quot;)</td>
<td>$3.0M</td>
<td>$3.0M</td>
</tr>
<tr>
<td>CIMNET Simultaneous Feasibility Test with Data Transfer Enhancements</td>
<td>$2.0M</td>
<td>$2.5M</td>
</tr>
<tr>
<td>Forward Capacity Auction (&quot;FCA&quot;) 13</td>
<td>$2.0M</td>
<td>$2.3M</td>
</tr>
<tr>
<td>nGEM Software Development</td>
<td>$1.8M</td>
<td>$2.6M</td>
</tr>
<tr>
<td>Storage Device Alternatives</td>
<td>$1.8M</td>
<td>$2.3M</td>
</tr>
<tr>
<td>Internal Market Monitoring Data Analysis Phase II</td>
<td>$1.3M</td>
<td>$1.3M</td>
</tr>
<tr>
<td>Energy Management Platform 3.2 Upgrade &amp; Customs Reduction</td>
<td>$1.0M</td>
<td>$1.3M</td>
</tr>
<tr>
<td>Operational Load Forecast: PV Integration</td>
<td>$1.0M</td>
<td>$1.1M</td>
</tr>
<tr>
<td>Identity and Access Management</td>
<td>$0.8M</td>
<td>$1.0M</td>
</tr>
<tr>
<td>2018 Issue Resolution Phase I</td>
<td>$0.8M</td>
<td>$0.8M</td>
</tr>
</tbody>
</table>

*Continued Next Page*
## Capital Budget
### 2018 Expenditures (con’t)

<table>
<thead>
<tr>
<th>In Planning/Conceptual Design (continued):</th>
<th>2018</th>
<th>Total Project Costs</th>
</tr>
</thead>
<tbody>
<tr>
<td>2018 Issue Resolution Phase II</td>
<td>$0.7M</td>
<td>$0.7M</td>
</tr>
<tr>
<td>Enterprise Application Integration</td>
<td>$0.6M</td>
<td>$0.8M</td>
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<tr>
<td>FERC Form 1, 3-Q, 714</td>
<td>$0.5M</td>
<td>$0.6M</td>
</tr>
<tr>
<td>Forward Capacity Market Improvements</td>
<td>$0.3M</td>
<td>$1.3M</td>
</tr>
<tr>
<td>Non-Project Capital Expenditures</td>
<td>$4.0M</td>
<td></td>
</tr>
<tr>
<td>Other Emerging Work</td>
<td>$2.8M</td>
<td></td>
</tr>
<tr>
<td>Capital Interest</td>
<td>$0.5M</td>
<td></td>
</tr>
</tbody>
</table>

**Total 2018 Capital Budget**  
$28.0M
ISO/RTO FINANCIAL COMPARISON
# Financial Results Summary

## ISO/RTO Financial Summary - 2016 Actual Results

Operating Expense and Capital Expenditures for Calendar Year 2016, and Outstanding Debt as of December 31, 2016

(Amounts in Millions)

<table>
<thead>
<tr>
<th></th>
<th>ISO-NE (2)</th>
<th>NYISO</th>
<th>CAISO</th>
<th>IESO (3)</th>
<th>PJM</th>
<th>MISO</th>
<th>SPP</th>
<th>ERCOT</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operating Expense - 2016</td>
<td>$181.6</td>
<td>$175.5</td>
<td>$204.2</td>
<td>$208.7</td>
<td>$337.6</td>
<td>$334.1</td>
<td>$214.7</td>
<td>$186.6</td>
</tr>
<tr>
<td>Less: Amortization &amp; Depreciation</td>
<td>$(32.1)</td>
<td>$(24.2)</td>
<td>$(23.7)</td>
<td>$(23.4)</td>
<td>$(50.2)</td>
<td>$(43.3)</td>
<td>$(58.0)</td>
<td>$(21.7)</td>
</tr>
<tr>
<td>Regulatory Fees</td>
<td>$(5.8)</td>
<td>$(12.7)</td>
<td>-</td>
<td>-</td>
<td>$(51.7)</td>
<td>$(49.3)</td>
<td>$(18.6)</td>
<td>$(14.0)</td>
</tr>
<tr>
<td>Grant Expenses</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Net Operating Expense - 2016</td>
<td>$143.6</td>
<td>$138.6</td>
<td>$180.5</td>
<td>$185.3</td>
<td>$235.7</td>
<td>$241.5</td>
<td>$138.0</td>
<td>$150.9</td>
</tr>
</tbody>
</table>

Other Financial Data

<table>
<thead>
<tr>
<th></th>
<th>ISO-NE (2)</th>
<th>NYISO</th>
<th>CAISO</th>
<th>IESO (3)</th>
<th>PJM</th>
<th>MISO</th>
<th>SPP</th>
<th>ERCOT</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital Expenditures for 2016</td>
<td>$24.6</td>
<td>$19.6</td>
<td>$35.4</td>
<td>$24.8</td>
<td>$36.0</td>
<td>$41.7</td>
<td>$14.3</td>
<td>$29.2</td>
</tr>
<tr>
<td>Outstanding Debt as of 12/31/2016</td>
<td>$108.7</td>
<td>$101.7</td>
<td>$191.4</td>
<td>$90.0</td>
<td>$22.1</td>
<td>$179.4</td>
<td>$256.5</td>
<td>$63.0</td>
</tr>
</tbody>
</table>

Actual full-time equivalent headcount as of 12/31/2016

572.5  538.0  596.0  676.0  692.0  879.0  581.0  713.0

(1) Applicable amounts were taken from each entity’s 2016 audited financial statements

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

(3) Amounts are in Canadian dollars
ISO-NE Responses to State Agencies' Questions regarding proposed ISO-NE 2018 Budget

(1) Please provide the latest copy of ISO-NE’s FERC Form 1.
   Hard copy will be provided to Seth Hollander via U.S. mail.

(2) Please provide the most recent copy of ISO-NE’s Form 990.
   Hard copy will be provided to Seth Hollander via U.S. mail.

(3) With respect to each of the three approved projects listed in the 2018 capital budget, please provide the actual FY2016, actual FY2017 and budgeted FY2018 personnel costs per project, separated by in-house employees versus outside contractors. If available, please provide the actual 2015, actual 2016 and budgeted 2017 FTE-equivalent numbers for each project, for in-house employees and for outside contractors.

Please see the table below providing this information. Please note that we have used averages of $85/hour for employees (fully burdened) and $96/hour for consultants to determine the employee and consultant costs. No costs were incurred in 2015, or prior, for the three listed projects. Each of these projects was chartered in 2017, at which time detailed budgets were established. Expenditures before that point (e.g., in 2016) were for planning and design. In 2017, to date, each of these projects is within its annual budget.

<table>
<thead>
<tr>
<th>Capital Projects - Approved Charters</th>
<th>2016 Actual Results</th>
<th>2017 Actual &amp; Remaining Forecast (1)</th>
<th>2018 Budget</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Int Labor $</td>
<td>FTE Equiv</td>
<td>Consult $s</td>
</tr>
<tr>
<td>. Price Responsive Demand (2)</td>
<td>$ 297,400</td>
<td>1.7</td>
<td>$ 293,751</td>
</tr>
<tr>
<td>. Forward Capacity Market - Pay for Performance</td>
<td>$ 114,369</td>
<td>0.6</td>
<td>$ 39,005</td>
</tr>
<tr>
<td>. Internal Mkt Monitoring Data Analysis Ph I (3)</td>
<td>$ 175,895</td>
<td>1.0</td>
<td>$ -</td>
</tr>
</tbody>
</table>

(1) 2017 includes actual results through July as well as the remaining forecast for the rest of the year. Actual amounts through July are $2,366.8K ($736.1K Internal Labor, $1,630.7K Consultants), $528.3K ($233.5K Internal Labor, $304.8K Consultants), and $243.7K ($223.1K Internal Labor, $10.6K Consultants) for Price Responsive Demand, Forward Capacity Market - Pay for Performance, and Internal Market Monitoring Data Analysis Phase I, respectively.

(2) The Price Responsive Demand project also includes $114,000 of hardware costs not reflected above.

(3) The Internal Market Monitoring Data Analysis Phase I project also includes $145,000 of hardware and software costs not reflected above.
With respect to the 2018 Capital Budget, for the top five projects listed for planning/conceptual design on page 90 of the August 11, 2017 power point presentation, please identify how much of the proposed budget estimate per project is for (a) internal ISO NE employee costs; (b) outside consultant costs; and/or (c) purchases of materials and/or programs.

Projects in planning/conceptual design do not have detailed resource allocations at this time. Rather, the preliminary budget is based on a high level review of systems impacted, as well as review of our past projects with similar work scope. All capital projects, prior to approval, must have a completed project charter which outlines the project’s goals and objectives, schedule and milestones, and budget. Before approving a new capital project, the ISO’s senior management team reviews each project charter. Once a project scope is determined and the project is chartered, detailed resource allocations are completed.

For the past three fiscal years, please provide details on whether FTE expenses for reimbursable studies were recovered and in what amounts. To the extent such expenses were unpaid or remain, please explain.

The following internal ISO-NE staff time was utilized and recovered for reimbursable studies. Amounts are fully burdened costs:

- 2014: $483,559 or approximately 3.50 FTEs
- 2015: $613,450 or approximately 4.50 FTEs
- 2016: $634,911 or approximately 4.50 FTEs

No expenses for 2014, 2015, or 2016 were unpaid.

With respect to the $4.0 million in the proposed 2018 capital budget for Non-Project Capital Expenditures, please provide a more detailed breakdown and description of what expenditures are included, including the $700,000 in Building Improvements, Machinery & Equipment, and Furniture & Fixtures (as indicated on page 108). Given the similarity to the breakdown in this category provided for the $4.1 million in the 2017 budget, please explain whether this is simply a set annual budget amount and breakdown or if it is specifically calculated per fiscal year.

The budget forecast in each of these categories is based on the historical level expenditures as well as a high level assessment of planned investments for the upcoming year.
$1.8M – System Improvement Requests: Annually, ISO-NE’s Information Services (IS) area addresses several hundred small requests to improve the existing software infrastructure. The IS department deploys a mixture of ISO internal employees as well as on-site contractors and vendors to address the list of open System Improvements. Each year the forecasted budget is reviewed to ensure the resources dedicated to this effort are not in conflict with the slated major projects. This budgeted amount is consistent with prior years and covers the cost of meeting these requests.

$1.5M – Non-Project Hardware: Annually, ISO-NE’s Information Services area invests in upkeep and upgrade of our existing hardware infrastructure. This year’s budget addresses System Hardware Refreshes, Data Storage Increases, Web Infrastructure Refresh, Upgrade of Configuration and Compliance Tool-sets, as well as Oracle Hardware Refresh.

$0.7M - Building Improvements, Machinery & Equipment, and Furniture & Fixtures: Annually, ISO-NE’s Building Services department invests in the upkeep and upgrading of our Main Control Center (MCC) and Backup Control Center (BCC) facilities. The 2018 budget includes funding for equipment and communications upgrades for the build out of a redundant phone system between the MCC and the BCC for disaster recovery purposes. Additional funding is included for the build out of work space for the Cyber Security Operations Center, the replacement of carpeting at the MCC, as well as other small miscellaneous items that arise throughout the year.
(7) Please provide the actual vacancy rates from 2011-2017, the vacancy rates in your budgets from 2011-2017, and your proposed vacancy rate for the 2018 budget.

Note: For 2017, the Actual Average Vacancy % is year-to-date through July.

<table>
<thead>
<tr>
<th>Year</th>
<th>Budgeted Vacancy %</th>
<th>Actual Average Vacancy %</th>
</tr>
</thead>
<tbody>
<tr>
<td>2011</td>
<td>5.0%</td>
<td>6.3%</td>
</tr>
<tr>
<td>2012</td>
<td>5.0%</td>
<td>2.6%</td>
</tr>
<tr>
<td>2013</td>
<td>2.5%</td>
<td>4.5%</td>
</tr>
<tr>
<td>2014</td>
<td>3.0%</td>
<td>3.2%</td>
</tr>
<tr>
<td>2015</td>
<td>3.0%</td>
<td>3.2%</td>
</tr>
<tr>
<td>2016</td>
<td>3.0%</td>
<td>3.8%</td>
</tr>
<tr>
<td>2017</td>
<td>3.0%</td>
<td>4.5%</td>
</tr>
<tr>
<td>2018</td>
<td>3.0%</td>
<td>N/A</td>
</tr>
</tbody>
</table>

(8) For Fiscal Years 2015 (actual), 2016 (actual), 2017 (current forecast) and proposed for 2018, please provide the total dollars spent on/for outside consultants by functional areas (i.e., the areas listed in the left-side of chart on page 29 of power point). For Information Services, please separate out cybersecurity expenses from all other expenses. Please also provide the corresponding FTE-equivalent of the consultants for the actual FY2015, actual FY2016 and budgeted for FY2017. (You may use average fully loaded payroll dollars [by functional area] to calculate the FTE (Consultant $/average payroll = FTE)). In last year's responses to the same question, the total FTE equivalents for outside consultants increased from 53.8 (2015 actual) to 63.1 (2016 then-current forecast) to 69.3 (2017 budgeted), with the largest increases in Information Services. Please provide an explanation for the increasing trend and whether the 2018 budget (or future budgets) will reverse that trend.

The requested information is provided in the table below (expense amounts in thousands). These figures include all Operating Budget Professional Fees.
The increases are discussed below. This summary does not reflect any decreases in professional fees that were articulated in the efficiencies, reductions and non-recurring costs captured in each of the respective years’ budget presentations.

From 2015 to 2016, consultant funding increased for work to prepare an updated calculation of Cost of New Entry (CONE) and net CONE for the 12th Forward Capacity Auction (FCA); to address Forward Capacity Market (FCM) De-list reviews, non-price retirements, and Pay for Performance; and related to an update to the Offer Review Trigger Price. The 2015 to 2016 increase also reflected funding for Cyber Security related support. These increases affected the Market Operations, Market Development and Information Services departments. System Planning saw an increase due to Order 1000 implementation and wind study work. Each of these increases was described in ISO-NE’s 2016 Budget Presentation.

From 2016 to 2017, consultant support increased in Information Services and Cyber Security specifically for: Cyber Security in the areas of desktop segregation and identity and access management; enhancements to the asset and license management function; Linux and Windows Audit & Security administration; and review and compliance with NERC CIP standards. Again, each of these increases was noted in ISO-NE’s 2017 Budget Presentation. Other increases are discussed in the next paragraph.

<table>
<thead>
<tr>
<th>Area</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Expense</td>
<td>FTE Equiv</td>
<td>Expense</td>
<td>FTE Equiv</td>
</tr>
<tr>
<td>System Operations</td>
<td>$670.9</td>
<td>3.3</td>
<td>$399.2</td>
<td>2.0</td>
</tr>
<tr>
<td>System Planning</td>
<td>$997.3</td>
<td>5.2</td>
<td>$1,329.9</td>
<td>6.9</td>
</tr>
<tr>
<td>Market Operations</td>
<td>$546.7</td>
<td>3.2</td>
<td>$648.7</td>
<td>3.7</td>
</tr>
<tr>
<td>Market Development</td>
<td>$282.5</td>
<td>1.3</td>
<td>$753.2</td>
<td>3.5</td>
</tr>
<tr>
<td>Information Services</td>
<td>$2,423.5</td>
<td>12.7</td>
<td>$2,535.8</td>
<td>13.3</td>
</tr>
<tr>
<td>Info. Services - Cyber Security</td>
<td>$87.7</td>
<td>0.5</td>
<td>$304.8</td>
<td>1.6</td>
</tr>
<tr>
<td>Program Mgt &amp; Bus Arch</td>
<td>$450.7</td>
<td>2.0</td>
<td>$564.7</td>
<td>2.5</td>
</tr>
<tr>
<td>Market Monitoring</td>
<td>$1,389.2</td>
<td>7.8</td>
<td>$1,207.9</td>
<td>6.8</td>
</tr>
<tr>
<td>Legal Services</td>
<td>$1,018.3</td>
<td>3.8</td>
<td>$906.8</td>
<td>3.4</td>
</tr>
<tr>
<td>Ext Affairs &amp; Corp Comm</td>
<td>$624.9</td>
<td>3.4</td>
<td>$647.5</td>
<td>3.5</td>
</tr>
<tr>
<td>Compl., Risk Mgt, Finance &amp; Int Audit</td>
<td>$988.4</td>
<td>5.2</td>
<td>$1,093.4</td>
<td>5.8</td>
</tr>
<tr>
<td>Human Resources</td>
<td>$1,305.3</td>
<td>5.4</td>
<td>$1,377.0</td>
<td>5.7</td>
</tr>
<tr>
<td>CEO &amp; COO &amp; Support</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Building Services</td>
<td>-</td>
<td>-</td>
<td>$19.7</td>
<td>0.2</td>
</tr>
<tr>
<td>Total</td>
<td>$10,785.4</td>
<td>53.8</td>
<td>$11,788.6</td>
<td>58.8</td>
</tr>
</tbody>
</table>

The increases are discussed below. This summary does not reflect any decreases in professional fees that were articulated in the efficiencies, reductions and non-recurring costs captured in each of the respective years’ budget presentations.

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From 2016 to 2017, consultant support increased in Information Services and Cyber Security specifically for: Cyber Security in the areas of desktop segregation and identity and access management; enhancements to the asset and license management function; Linux and Windows Audit & Security administration; and review and compliance with NERC CIP standards. Again, each of these increases was noted in ISO-NE’s 2017 Budget Presentation. Other increases are discussed in the next paragraph.
The 2018 outside consultant fees and FTE Equivalents are largely in line with the original 2017 budget (2017 budget was $14,000,200, 69.3 FTE) but less than the 2017 current forecast included in the table above. The current 2017 forecast includes additional work that was not planned for originally, including work related to the second phase of the Economic Study for NEPOOL Scenario Analysis (System Planning and Market Operations) and an analysis of the Winter Reliability program (Market Development). These increased professional fees projected for 2017 are being covered by reallocated savings in other line items, as explained quarterly during the financial review with the NEPOOL Budget and Finance Subcommittee. These quarterly results are posted to the ISO’s website.

The use of outside consultants varies year to year based upon the business objectives laid out in the ISO’s business plan that is reviewed with stakeholders. The ISO strives to utilize cost effective resources, in the form of consultants, to meet short term needs. For example, as discussed during last year’s budgeting process and as noted above, the ISO used an increased number of consultants in the cyber security area as the most cost effective way to meet immediate needs while also evaluating future needs.
September 6, 2017

Philip Shapiro  
Chairman  
ISO New England  
One Sullivan Road  
Holyoke, MA 01040

RE: Comments on proposed 2018 ISO New England Operating & Capital Budgets

Dear Chairman Shapiro:

On behalf of the undersigned New England state agencies, we submit our comments regarding the ISO New England proposed 2018 Operating and Capital Budgets.

We appreciate the ISO-NE’s response to the feedback provided at the June 2017 NECPUC state budget session. We note that although the operating and capital budget amounts remain the same (cash budget increase of 3.0% for a $192.6 million cash budget), the revenue requirement was reduced from $197.4 million (a 2.6% increase) proposed in June to $196 million (a 1.9% increase) proposed in August. We understand that the decrease from June to August is due to the reduction of the depreciation expense, from a proposed $32.4 million in June to a proffered $31 million in August. Thus the $/kWh rate increase was reduced from a proposed 1.3% in June to a mere 0.7% increase in August. We note with approval that this rate increase is significantly lower than the rate increases for the two prior years.

Further, although we are never enthusiastic to see an increased headcount, we understand ISO NE’s specific need in this case to expand its in-house cybersecurity team and thus do not object to the proposal to increase the approved headcount for that purpose. We do, however, suggest that the operating budget be modified to include a modest increase in the vacancy rate in order to bring the vacancy rate more in line with actual experience.
1. **A modest increase in the vacancy rate will conform to actual experience.**

   Over the past five years, ISO-NE's full-time employees (FTEs) in the budget have increased from 560 FTEs in 2013 to 590 FTEs proposed in 2018. The number of budgeted FTEs is calculated by the overall headcount, less the vacancy rate. In other words, as the vacancy rate used in the budget increases, the number of budgeted FTE positions, and the operating budget total amount, decrease.

 ISO-NE's budgeted versus actual vacancy rates are as follows:

<table>
<thead>
<tr>
<th>Year</th>
<th>Budgeted Vacancy %</th>
<th>Actual Average Vacancy %</th>
</tr>
</thead>
<tbody>
<tr>
<td>2011</td>
<td>5.0%</td>
<td>6.3%</td>
</tr>
<tr>
<td>2012</td>
<td>5.0%</td>
<td>2.6%</td>
</tr>
<tr>
<td>2013</td>
<td>2.5%</td>
<td>4.5%</td>
</tr>
<tr>
<td>2014</td>
<td>3.0%</td>
<td>3.2%</td>
</tr>
<tr>
<td>2015</td>
<td>3.0%</td>
<td>3.2%</td>
</tr>
<tr>
<td>2016</td>
<td>3.0%</td>
<td>3.8%</td>
</tr>
<tr>
<td>2017</td>
<td>3.0%</td>
<td>4.5%</td>
</tr>
<tr>
<td>2018</td>
<td>3.0%</td>
<td>N/A</td>
</tr>
</tbody>
</table>

We respectfully submit that using a 3.0% vacancy rate is too conservative – resulting in an over-collection from New England ratepayers – and request that a higher vacancy rate be used in the 2018 operating budget. We propose that a 3.8% vacancy rate be used for the 2018 budget. Using a 3.8% vacancy rate is consistent with the average actual vacancy rate over the past three years and would reduce the overall headcount of 608 by 23 FTEs, funding 585 FTEs rather than 590 FTE proposed in the budget.\(^1\) Coincidently it would maintain the same number of funded FTE positions as last year, while increasing the overall headcount by five positions.

2. **Opportunities for future reductions in the expense.**

   As the Board is aware, electricity expenses in New England are the highest in the country, and those expenses are an important variable that contribute to the region's competitiveness and prosperity. Further, on the majority of comparative

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\(^1\)See ISO New England Proposed 2018 Operating and Capital Budgets power point, dated August 11, 2017 (Budget power point) at slide 67 for FTE head counts and impact of vacancy rates.
measures, ISO-NE is the most expensive regional transmission operator in the continental U.S. We note that over the past five years, the ISO-NE operating budget revenue requirements have increased from an annual budget of approximately $165 million in 2013 to a requested $196 million for 2018. We believe this rate of increase is unsustainable in the long run.

We understand that there are legacy expenses embedded in the tariff, such as economic studies, that could be either eliminated or reduced in frequency. We thus respectfully propose that the state agencies meet with ISO-NE management to discuss which expenses contained in the current tariff structure might be eliminated in order to reduce the overall costs. We also note that the $28 million set forth in the capital budget has been set at the same level for the past five years. ISO-NE has completed several large capital projects over the past five years. As the fruits of those projects start to ripen, the number of necessary new projects has reduced. Thus, the amount entered into service in 2017 is less than what was retired, as reflected in the decrease in depreciation expense from 2017 to 2018. This is normal and to be expected. The capital budget should reflect this ebb and flow rather than staying at a static level.

However, rather than address these structural concerns in a once-a-year letter at the end of the budgeting process, we would propose to work with ISO-NE on suggestions that could be vetted through the NEPOOL stakeholder process, and might result in changes to the tariffs. We would welcome ISO-NE’s suggestions as to how best to collaborate and confer in such an endeavor.

CONCLUSION

We applaud the modest increase proposed in the overall rate. We note that a small change to conform the vacancy rate to actual experience would better reflect the actual expected payroll cost. We also invite the ISO-NE to explore with the states which legacy expenses contained in the current tariff structure might be eliminated or reduced in order to reduce the overall costs. We appreciate the opportunity to provide our thoughts directly to the Board, and thank you for your consideration.
Respectfully submitted,

Katherine Scharf Dykes  
Chair  
Public Utilities Regulatory Authority  
Ten Franklin Square  
New Britain, CT 06051

Elin Swanson Katz  
Consumer Counsel  
Office of the Consumer Counsel  
Ten Franklin Square  
New Britain, CT 06051

Margaret E. Curran  
Chairperson  
Rhode Island Public Utilities Commission  
89 Jefferson Blvd  
Warwick, RI 02888

Rhode Island Division of Public Utilities and Carriers  
By: Leo J. Wold  
Assistant Attorney General  
150 South Main Street  
Providence, RI 02903

Maura Healey  
Attorney General  
By: Rebecca L. Tepper  
ETD Division Chief  
Massachusetts Attorney General Office of Ratepayer Advocacy  
One Ashburton Place  
Boston, MA 02108-1598

Agnes Gormley  
Deputy Public Advocate  
Maine Office of the Public Advocate  
102 Water Street  
Hallowell, ME 04347

D. Maurice Kreis  
Consumer Advocate  
Office of the Consumer Advocate  
21 South Fruit Street, Suite 18  
Concord, NH 03301
New England States Committee on Electricity

2018 Budget Presentation
NEPOOL Budget & Finance Subcommittee
August 11, 2017
**Background: Budget Review**

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

- Proposed 2018 budget conforms to:
  1) Boundaries of previously reviewed 5-year pro forma (2018 - 2022) supported in June 2017 by NEPOOL & filed with the FERC
  2) NESCOE commitment not to seek an increase over pro forma budget of more than 10% in any 1 year - 2018 proposed budget is less than 2018 5-year pro forma budget

- Following calendar year 2016, independent auditor concluded NESCOE books conform to generally accepted accounting principles
Background: Policy Priorities

Term Sheet Provision Governing Identification of Policy Priorities

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

Consistent with Term Sheet, *2016 Report to the New England Governors*:

- Reviewed work in 2016
- Projected policy priorities
- Provided spending from prior year
- Projected budget information for upcoming two years
NESCOE provided to the Governors the *2016 Annual Report to New England Governors*

Report simultaneously released to NEPOOL & ISO-NE & circulated to the NEPOOL Participants Committee in April 2017

NESCOE identified forward looking policy priorities at Section V, pages 31-34

Projected Policy Priorities, Update

Power System Performance and Reliability:

✓ To the extent ISO New England continues to conclude, through its Fuel Security Analysis or otherwise, that New England's power system is “precarious” due to lack of consistently adequate fuel supplies and explores solutions to bolster reliability, assess and/or advance proposals as appropriate to ensure that any operational or market design solution(s) make the most economic sense for consumers and the environmental requirements of various states’ laws.

✓ Assess the early results of ISO New England’s Pay for Performance program, and ISO New England’s concern about the potential for incentives to be insufficient to ensure fuel security during winter months.

Accommodation of Public Policy in Markets:

✓ Continue to advocate to ensure reasonable and necessary harmonization in the regional electricity market of energy and environmental policies.

✓ Continue to defend New England’s narrowly tailored renewable resource exemption or its equivalent in any CASPR-like proposal.

✓ Actively participate in any regional work and/or FERC proceedings that follow the NEPOOL Integrating Markets and Public Policy process, including continued assessment of CASPR and long-term proposals.

Transmission Planning/Analysis, Transmission Cost Estimation, Containment and Reporting Practices:

✓ Continue to seek progress on enhancing consistency and transparency in regional transmission system planning and rates, including but not limited to improvements in transmission cost estimation, containment and rate reporting practices.
Employees
- Diversity in academic training, skills; blend of private & public sector experience
- Current total employee level: 5
  - Based on current need and skill assessment, anticipate return to steady state of 6 during 2018

Office Space
- 4 Bellows Road, Westborough, MA
  - Current lease through September 2017; anticipate renewal
  - Also provides small group meeting space needs
- Small room in Portsmouth, New Hampshire
  - Current lease through 2017; anticipate renewal
Technical Consultants

Technical consultants, such as transmission engineers and economists, assist NESCOE in the regular course of business in analyzing ISO-NE studies and data.

Continue work with technical consultants to conduct independent analysis to inform state officials’ decisions on key issues. Primary growth in spending will relate to increased use of consultants to conduct independent analysis for state officials.

- Wilson Energy Economics - assistance with economic analysis
- PeterGFlynn, LLC - New England transmission cost and infrastructure expertise
- Reishus Consulting, LLC - electric industry research and analysis
- London Economics International - modeling in connection with Clean Energy Mechanisms Study 2.0

Legal Counsel

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

- FERC Counsel: McCarter & English LLP
Proposed 2018 budget conforms to 2018 budget in 5-year Pro Forma Framework

- 2018 Projected Budget in 5 Year Pro Forma: $2,325,741
  (supported by NPC in June 2017 & filed with FERC)
- 2018 Proposed Budget: $2,282,317
- 2017 Budget, for reference: $2,258,001

In relation to 2018 5-year Pro Forma, 2018 Proposed Budget reflects:

- Reduction in organizational Professional Services (i.e., bookkeeping, legal, audit, etc.) based on recent experience
- Technical Consulting maintained at 2017 level
# 5 Year Pro Forma, for reference

## NESCOE
**PRO FORMA BUDGET 2018-2022***

<table>
<thead>
<tr>
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<tbody>
<tr>
<td><strong>Salaries and Wages</strong></td>
<td></td>
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<td><strong>General and Administrative</strong></td>
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<td><strong>Capital Expenditures &amp; Contingencies</strong></td>
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<td><strong>TOTAL EXPENSES</strong>*</td>
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*Based on projected 3% annual adjustment. Line items and categories subject to increase greater than, or decreases from, amounts projected. Any such changes will be subject to review, input, and recommendations by the NEPOOL Participants Committee (and/or its designees).

**At no time during this 5-year period will NESCOE seek a budget increase of more than 10% in any 1 year or more than 30% on a cumulative basis.
## 2018 Proposed Budget

### NEPOOL PARTICIPANTS COMMITTEE

**SEP 15, 2017 MEETING, AGENDA ITEM #6.b**

### NESCOE Pro Forma Budget

**Preliminary 2018**

<table>
<thead>
<tr>
<th>Description</th>
<th>2018</th>
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<tbody>
<tr>
<td><strong>Salaries and Wages</strong></td>
<td></td>
</tr>
<tr>
<td>Salaries</td>
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<tr>
<td>Retirement §401(k)</td>
<td>39,321</td>
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<tr>
<td><strong>Total, Salaries and Wages</strong></td>
<td><strong>1,203,143</strong></td>
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</table>

| **Direct Expenses - Consulting**         |               |
| Technical Analysis                       | 502,700       |
| Legal (FERC)                             | 140,689       |
| **Total, Direct Expenses, Consulting**   | **643,389**   |

| **General and Administrative**           |               |
| Rent                                     | 27,000        |
| Utilities                                | 5,305         |
| Office and Administrative Expenses       | 43,497        |
| Professional Services                    | 55,000        |
| Travel/Lodging/Meetings                  | 90,000        |
| **Total General and Administrative**     | **220,802**   |

| **Capital Expend. & Contingencies**      |               |
| Computer Equipment                       | 7,500         |
| Contingencies                            | 207,483       |
| **Capital Expend. & Contingencies**      | **214,983**   |

**TOTAL EXPENSES**                        | **2,282,317** |

**BUDGET**                                 | **2,325,741** |
Unspent funds in any year credited toward future year

Expenses increasing over time, commensurate with substantive activity and analysis

2016 Total Spending: $1,437,274 *
2017 Spending to end of June: $638,306
2017 Projected Year End: $1,536,025 *

* Cumulative prior years’ true up, including 2015, was reflected in the 2017 revenue requirement and rates. The 2016 true up will be reflected in the 2018 revenue requirement and rates (see following slide). Any 2017 true up will be reflected in the 2019 revenue requirements and rates.

reflects consultant expenses for modeling services in connection with Clean Energy Mechanisms 2.0 Study and other analysis in the latter half of 2017
2018 Projected Billing Rate

With thanks to ISO-NE for calculations -

2018 Budget: $2,282,317

Less 2016 True Up: ($752,672)

Total Revenue Recovery: $1,529,645

Divided by Total Network Load: 233,550,045

(total network load from 2017 ISO-NE tariff; no escalation or reduction used in calculation)

2018 Schedule 5 Estimated Rate: $0.00655 per kW-month
Thank you.
Questions?
MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: David A. Cavanaugh, Chair, NEPOOL GIS Agreement Working Group
       Paul N. Belval, NEPOOL Counsel

DATE: September 8, 2017

RE: Amended and Restated GIS Administration Agreement Between NEPOOL and APX
    Amendment of GIS Operating Rules – Enhancements to the GIS

The Participants Committee will be asked at its September 15 meeting to approve
improvements to NEPOOL’s Generation Information System (“GIS”) arrangements. Those
improvements are reflected in a proposed Amended and Restated Generation Information
System Administration Agreement between NEPOOL and APX, Inc. (the “GIS Agreement”) and
accompanying change to GIS Operating Rule 1.3.

On September 1, 2017, the Markets Committee received a memorandum providing
background of the GIS Agreement amendment process and describing the more significant
changes that would be made by the GIS Agreement and to Rule 1.3, which is available at:
https://www.iso-ne.com/static-assets/documents/2017/09/a7_memo_re_gis_agreement_with_apx.pdf. As the GIS Agreement
includes some confidential, competitively sensitive information, the redacted GIS Agreement
and change to Rule 1.3 are available at:
transmittal, the Participants Committee members will receive a confidential memorandum
describing the competitively sensitive information and the unredacted GIS Agreement.

The following forms of resolution could be used for Participants Committee action:

RESOLVED, that the Participants Committee approves the Amended and
Restated Generation Information System Administration Agreement with
APX, Inc., as circulated to the Committee and discussed at this meeting,
together with any non-substantive changes as the Chairman of the GIS
Agreement Working Group may approve.

RESOLVED, that the Participants Committee approves the changes to GIS
Operating Rule 1.3, as circulated to the Committee and discussed at this
meeting, together with [any changes agreed to at this meeting and] such
further non-substantive changes as the Chairman of the GIS Agreement
Working Group may approve.
MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Pat Gerity, NEPOOL Counsel

DATE: September 8, 2017

RE: Vote on ISO-NE Planning Procedure 4-1 Revisions

At the September 15, 2017 Participants Committee meeting you will be asked to vote to support revisions to ISO-NE Planning Procedure 4-1 (Supplemental Guidelines for Pool-Supported PTF Cost Review) (“PP-4-1 Revisions”). The ISO proposed PP-4-1 Revisions to clean up some of the existing language regarding cost responsibility for generator interconnection transmission upgrades and Elective Transmission Upgrades. A copy of the PP 4-1 Revisions can be found at https://www.iso-ne.com/static-assets/documents/2017/08/a7_2_pp_4_1.zip.

At its August 24, 2017 meeting the Reliability Committee voted unanimously to recommend Participants Committee support for the PP-4-1 Revisions. The PP-4-1 Revisions were non-controversial and should have been on the Consent Agenda.

Absent objection, the PP-4-1 Revisions will be voted together with the September 15 Consent Agenda, using the following form of resolution:

RESOLVED, that the Participants Committee supports the PP-4-1 Revisions, as recommended by the Reliability Committee at its August 24, 2017 meeting and as reflected in the revised materials posted on the Reliability Committee’s webpage, together with such further non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee.
MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Eric Runge, NEPOOL Counsel

DATE: September 8, 2017

RE: PP-4 Attachment A Revisions

At the September 15, 2017 Participants Committee meeting you will be asked to vote to support revisions to ISO-NE Planning Procedure 4, Attachment A (Supplemental Guidelines for Pool-Supported PTF Cost Review) (the “PP-4 Attachment A Revisions”). The ISO has proposed the PP-4 Attachment A Revisions to provide guidance on transmission cost allocation for transmission projects with multiple parts. A copy of the PP-4 Attachment A Revisions, which reflect non-material changes identified at, but reflected after, the meeting, as well as the ISO’s presentation on the changes, has been included with this memorandum.

At its August 24, 2017 meeting the Reliability Committee voted to recommend Participants Committee support for the PP-4 Attachment A Revisions, with four Publicly Owned members opposed and no abstentions. Those members that opposed the PP-4 Attachment A Revisions have asked for this item to be placed on the discussion agenda so that they can highlight an issue they have with the implementation of the transmission cost allocation rules. We have included a memo from them with the materials for this item.

The following resolution could be used for Participants Committee consideration of the PP-4 Attachment A Revisions:

RESOLVED, that the Participants Committee supports the PP-4 Attachment A Revisions, as recommended by the Reliability Committee at its August 24, 2017 meeting and as reflected in the materials distributed to the Participants Committee for its September 15, 2017 meeting, together with [any changes agreed to at the meeting and] such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee.

1 The following two non-material changes were suggested during Reliability Committee consideration and later reflected in the Revisions included with this memorandum: (i) a carriage return was inserted back into the list of examples for projects that would be considered to contain Localized Costs; and (ii) a reference to the ISO-NE Transmission Planning Technical Guide was inserted in Example #5 in the list of examples for projects that are not likely to contain Localized Costs.
To: Participants Committee
From: Gabriel Stern - CMEEC, Brian Forshaw
Date: September 7, 2017
Subject: CMEEC Concerns with Proposed Changes to Planning Procedure #4 - Attachment A

At its August 24, 2017 meeting the Reliability Committee approved a set of changes to Planning Procedure 4 - Attachment A - Supplemental Guidelines for Pool-Supported PTF Cost Review (PP4-A). CMEEC and several other public power systems opposed these changes. While this iteration of changes appears to have little direct impact on the public power sector, the ISO’s implementation of related Technical Planning Guidelines has been problematic for CMEEC and other members of the sector. CMEEC is opposing these PP4-A changes in hopes of a broader discussion and consideration by stakeholders of the implications of PP-4A generally, to highlight the impacts of evolving, underlying transmission planning practices regarding “Development of the RSP” and “Assumptions for Studies”.¹

Discussion

Based on recent experience, CMEEC has serious concerns about recent ISO interpretation and implementation of the provisions in this planning procedure and Appendix A. PP 4-A provides some guidance on when the costs of PTF transmission upgrades installed under Prudent Utility Practices for maintaining regional load service reliability should be localized (rather than allocated to load across the region). PP4-A as written now, and as proposed for updating, lists some conditions for categorizing a project as containing localized costs, and presumably by implication, projects meeting any of these conditions are not eligible for regional cost recovery. Of particular concern to CMEEC is item 2 which states “The project does not address a need identified in a Needs Assessment through the Regional System Planning Process.” At the root of this objection is recent application by ISO-NE of a loss of load qualification criteria for inclusion of certain PTF project infrastructure for regional cost recovery. This approach is a departure from past practice. The ISO’s new qualification guidelines preclude a potential PTF infrastructure project from qualifying for regional cost recovery, unless such additions address an RSP identified need where a loss of load of more than 100 MW occurs on a first contingency (N-1) or more than 300MW load loss occurs on a second contingency (N-1-1).² Such project additions are eligible for cost regionalization if they are proposed as a preferred solution to a need identified by the ISO within the Regional System Plan. Remarkably the “100/300” criteria is not documented in ISO’s planning guidelines and has not been formally reviewed or endorsed by the NEPOOL Participants.³

Traditionally the criteria for regional cost recovery has been that the project meet the technical and functional definition of PTF plus meet a reliability need within the sponsor’s service territory with neutral or positive impact on the surrounding transmission system. This 100/300 criteria may serve, in part, to prevent smaller projects (that probably would not benefit from a competitive process) from being opened

¹ See ISO NE April 6, 2017 “Transmission Planning Process Guide” at 6.1 “Role of the PAC”
² ISO NE is also proposing to change some modeling assumptions regarding load levels and generation availability in a manner that may impact need thresholds.
³ ISO-NE’s draft “Transmission System Planning Load Interruption Guidelines” introduced November 17, 2010 puts forth this criteria. Stakeholder’s invited comments uniformly questioned the proposed “load loss” criteria. ISO has not responded and these guidelines have not been finalized through the stakeholder process nor submitted to FERC. On March 24, 2017 ISO-NE still describes, at Section 21, page 55 of its “Transmission Planning Technical Guide” that load loss criteria is “under development,” and yet today relies on the “100/300” criteria to qualify a need for solutions within transmission studies.
up to competition under Order 1000. The unfortunate side effect of this approach however is that it also
prevents any project that falls below the 100/300 criteria threshold from being considered for inclusion in
the RNS rate. As a result, small electric systems may now be burdened with the entire cost of PTF
upgrades that are needed and used to maintain reliability to loads and serve load growth within their
territory and neighboring environs, notwithstanding the fact that many similar projects (and any potential
asset condition replacements) are already included in the RNS rate. This leads to a situation where going
forward such smaller systems will be responsible for the full cost of certain facilities, while also
continuing to support a share of similar facilities owned by other systems through the RNS rate. CMEEC
believes this transmission rate treatment discriminates between similarly situated facilities on the
administered transmission system and also between larger and smaller transmission owners. CMEEC also
views the 100/300 criteria as a material rate, term, or condition change that warrants, at a minimum,
considerable stakeholder review and discussion. We also understand that other RTO regions do not link
regional cost recovery to loss of load criteria as ISO-NE is attempting to do in applying its draft planning
guidelines and we do not believe that Order 1000 requires such treatment.

ISO-NE, at least for the moment, has reduced its responsibility for certain transmission facilities and has
done so without consideration of cost responsibility or equity for maintaining reliability of service.4
CMEEC believes that left unchanged, application of the 100/300 criteria will produce “unjust,
unreasonable and unduly discriminatory” results. One region-wide RNS rate is charged throughout the
region, yet two levels of regionally supported service reliability may prevail. With uniform transmission
pricing in New England, a reasonable corollary is that ISO-NE transmission-level loss of load tolerances
should allow all customers to enjoy similar load reliability at the administered transmission system level.5

Conclusion

For these reasons, CMEEC opposes the proposed changes to Planning Procedure 4 - Attachment A.
CMEEC believes that a broader discussion by stakeholders is critically needed to consider these
implications and the impact of the evolving transmission planning process on consumers and other
entities that support the cost of new and existing transmission facilities.

---

4 The draft Guidelines 100/300 load loss criteria reduces ISO-NE depth of concern for reliability and narrows the definition of
regionally eligible facilities; this runs counter to a recent NERC expansion of definition of regionally critical facilities to include
everything qualifying as part of the BES, defined as transmission plant of greater than 100kV voltage level. It also overrides, for
facilities associated with sub benchmark loads, the more traditional discrete system condition measures.

5 Modeling criteria and approach lie at the root of the equity issue. Modeling in New England post Order 1000 now looks only at
violations of high voltage level system impacts. Customer load impact is not directly considered. Further no consideration is
given to relative significance, consequence, or strategic value of load at risk of loss, nor to deliberate recent actual operational
experience. No matter how real and ongoing, non-NERC mandated-for-review contingencies are ignored. The conditions causing
some line and related equipment in the field to have failed or teetered near failure multiple times may go unaddressed in Solution
studies if those conditions are not precisely qualified as comporting with NERC guidelines for contingency studies. Modeling
results based solely on broad, set benchmark load loss criteria cannot be relied upon to serve public need for reliable power.
Attachment A
Supplemental Guidelines for Pool-Supported PTF Cost Review

In determining whether there are Localized Costs, the ISO will consider as appropriate and with the advisory input of the RC, the following non-exclusive list of factors:

1. Costs of construction including all costs associated with rights of way, easements and associated real estate.
2. Assessment of the schedule or in-service date of the Project from an engineering and construction standpoint rather than from the standpoint of potential delays in local or state siting.
3. Relative reliability and operational impacts of the Project as compared to alternatives considered.
4. Costs associated with operation and maintenance of the proposed design and alternatives, including consideration of whether the proposed design is consistent with Good Utility Practice.
5. Costs of related and long-term congestion impacts, if any, of each proposed PTF and Non-PTF design alternative, including costs related to outages associated with construction.
6. The proposed design’s fit into reasonable future expansion plans, including the Regional System Plan.
7. Consistency with current engineering, design and construction practices in the area.

The following, non-exclusive list of examples is provided for illustration of the types of Projects that would be considered to contain Localized Costs:

1. The Project costs more than a feasible or practical transmission alternative and has equal or less robust bulk power system performance than the transmission alternative.
2. The Project does not address a need identified in a Needs Assessment through the Regional System Planning Process.
3. The Project includes one or more underground transmission cables, which is selected (a) at the direction of a local or state siting board, or (b) to address other local concerns, and the cost of overhead transmission lines is less expensive, taking into account all relevant costs.
4. The Project is a gas-insulated or covered substation when an open-air substation would be feasible and practical for lower cost.
5. Installation of one or more Independent Pole Tripping breakers at a substation operating at less than 345 kV without a stability need.

The following, non-exclusive list of examples is provided for illustration of the types of Projects that are not likely to contain Localized Costs:

1. The Project includes one or more underground transmission cables but the total cost of the underground transmission cable Project is lower than a feasible and
practical overhead transmission line, the operating and maintenance costs are comparable, and the reliability benefits provided by the underground cable are equal to or better than those provided by the overhead line.

2. The Project has higher total cost than feasible and practical transmission alternatives, but provides for more robust bulk power system performance consistent with the Regional System Plan (RSP) planning horizon and predicted load growth when compared to such transmission alternatives.

3. Installation of one or more Independent Pole Tripping breakers at a substation operating at less than 345 kV where the effects of a three-phase breaker failure contingency shows an unacceptable response, as described in the ISO-NE Transmission Planning Technical guide, inter area impact.

4. Installation of one or more Independent Pole Tripping breakers at a 345 kV substation.

5. In general, when the failure of a breaker violates planning criteria, as described in the ISO-NE Transmission Planning Technical Guide, or produces unacceptable operational consequences that are solved by the installation of a series breaker, the series breaker cost will be deemed acceptable.
Proposed Additions to Planning Procedure 4 Attachment A

Relocation of Substation Equipment Cost Allocation guidance language

Michael Drzewianowski
(413) 540-4419 | MDRZEWIANOWSKI@ISO-NE.COM
Proposed Additions to Planning Procedure 4 (PP4) Attachment A

Proposed Effective Date: Q3 of 2017

• PP4 Attachment A - *Supplemental Guidelines for Pool-Supported PTF Cost Review* provides direction on what parts of a Project may lead to localization of costs.

• This presentation provides an overview of the proposed PP4 Attachment A revisions currently being considered by ISO.
  
  – The proposed revisions provide additional direction and clarification on what parts of a Project may/may not be subject to localize costs.
Background

• During the June 20, 2017 Reliability Committee discussion on revisions to Planning Procedure 9 (PP9), stakeholders indicated that the cost allocation guidance language, though useful, did not seem to belong in PP9.
Problem Statement

• In recognition of stakeholder guidance and the proposed removal of the material from PP9, identify a more suitable location for the cost allocation guidance language.
Proposal

- ISO-NE has identified PP4 Attachment A as the best location to place the PP9 cost allocation guidance language and recommends that PP4 Attachment A be modified accordingly.

- The modification of PP9 and PP4 Attachment A will be made simultaneously.
Proposal Details

• Coincident with the removal of the language from PP-9, PP-4 Attachment A is proposed to be revised as follows:
  – Under **would be** considered to contain Localized Costs, add:
    • Installation of one or more Independent Pole Tripping breakers at a substation operating at less than 345 kV without a stability need.
  – Under **not likely** to contain Localized Costs, add:
    • Installation of one or more Independent Pole Tripping breakers at a substation operating at less than 345 kV where the effects of a three-phase breaker failure contingency shows unacceptable inter-area impact.
    • Installation of one or more Independent Pole Tripping breakers at a 345 kV substation.
    • In general, where the failure of a breaker violates planning criteria or produces unacceptable operational consequences the installation of a series breaker will be deemed acceptable.
  – Minor grammar clean up was also performed on the section.
Conclusion

• In recognition of stakeholder guidance, the ISO proposes to relocate the cost allocation discussion from Planning Procedure 9 to Planning Procedure 4 Attachment A.

• It is anticipated to have this voted on at the August RC meeting.
## Stakeholder Schedule

<table>
<thead>
<tr>
<th>Stakeholder Committee and Date</th>
<th>Scheduled Project Milestone</th>
</tr>
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</table>
| Reliability Committee July 19, 2017 | • Overview of conceptual PP4 Attachment A proposed revisions  
                                            • Review PP4 Attachment A redline  
                                            • Seek stakeholder comments                                                               |
| Reliability Committee August 24, 2017 | • Discuss any stakeholder comments received and any additional PP4 Attachment A revisions  
                                            • Seek RC Vote                                                                                |
| Participants Committee September 15, 2017 | • Vote                                                                                     |
Questions

Michael Drzewianowski

(413) 540-4419 | MDRZEWIANOWSKI@ISO-NE.COM
To: Participants Committee  
From: Marc Lyons, Secretary – Reliability Committee  
Date: August 24, 2017  
Subject: ACTIONS OF THE RELIABILITY COMMITTEE

This memo is to notify the Participants Committee ("PC") of the actions taken by the Reliability Committee ("RC") at its August 24, 2017 meeting.

(Agenda Item 2.0) Meeting Minutes  
The following motion was moved and seconded by the Reliability Committee:

Resolved, the Reliability Committee recommends that ISO New England Inc. approve the previously distributed minutes of the following RC meeting:

- July 18 & 19, 2017  
- August 1, 2017  

The motion was voted. Based on a show of hands, the motion passed with none opposed and no abstentions.

(Agenda Item 4.1) Number Nine Wind Farm Generation and Transmission Project - Proposed Plan Applications (PPAs) NN-17-G01, NN-17-G02, NN-17-T01, NN-17-T02, NN-17-T03, NN-17-T04, NN-17-X01, and CMP-17-T02

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

Resolved, the Reliability Committee recommends that ISO New England Inc. determine that implementation of the Number Nine Wind Farm Generation and Transmission Project described in Proposed Plan Applications ("PPAs") NN-17-G01, NN-17-G02, NN-17-T01, NN-17-T02, NN-17-T03, NN-17-T04, NN-17-X01, and CMP-17-T02 from Number Nine Wind Farm, LLC ("NN") and Central Maine Power Company ("CMP"), as detailed in their August 16, 2017 and August 14, 2017 transmittals to ISO New England and distributed to the committee for the August 24, 2017 meeting, will not have a significant adverse effect on the stability, reliability or operating characteristics of the transmission facilities of the applicant, the transmission facilities of another Transmission Owner or the system of a Market Participant.

The motion was then voted. Based on a show of hands, the motion passed with none opposed and no abstentions. Motion passes.
(Agenda Item 5.1) PTF Cost Allocation - TCA Application UI-17-TCA-01

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

Resolved, the Reliability Committee recommends that ISO New England approve, as consistent with the criteria set forth in Section 12C of the ISO New England Open Access Transmission Tariff for receiving regional support and inclusion in Pool-Supported PTF Rates, the Pool-Supported PTF costs of $17.82M (2017 Estimated Costs) for work associated with the construction of the Baird Substation Rebuild Project as described in the TCA Application UI-17-TCA-01, submitted August 8, 2017 by Avangrid as distributed to the committee for the August 24, 2017 meeting.

The motion was voted. Based on a show of hands, the motion passed with none opposed and no abstentions.

(Agenda Item 7.2) ISO New England Planning Procedure No. 4-1

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

Resolved, the Reliability Committee recommends Participants Committee support for revision of ISO New England Planning Procedure No. 4-1 – Cost Responsibility for Transmission Upgrades with Multiple Needs and distributed to the committee for the August 24, 2017 meeting, together with such other changes as discussed and agreed to at the meeting, and such other non-material changes as may be approved by the Chair and Vice-Chair of the Reliability Committee following the meeting.

The motion was then voted. Based on a show of hands, the motion passed with none opposed and one abstention (1 Supplier Sector).

(Agenda Item 7.3) ISO New England Planning Procedure No. 9

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

Resolved, the Reliability Committee recommends Participants Committee support for revision of ISO New England Planning Procedure No. 9 – Major Substation Bus Arrangement Application Guidelines and distributed to the committee for the August 24, 2017 meeting, together with such other changes as discussed and agreed to at the meeting, and such other non-material changes as may be approved by the Chair and Vice-Chair of the Reliability Committee following the meeting.

The motion was then voted. Based on a show of hands, the motion passed with none opposed and one abstention (1 Supplier Sector).
(Agenda Item 7.4) ISO New England Planning Procedure No. 4 Attachment A

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

Resolved, the Reliability Committee recommends Participants Committee support for revision of ISO New England Planning Procedure No. 4 Attachment A – Procedure for Pool Supported Cost Review and distributed to the committee for the August 24, 2017 meeting, together with such other changes as discussed and agreed to at the meeting, and such other non-material changes as may be approved by the Chair and Vice-Chair of the Reliability Committee following the meeting.

The motion was then voted. Based on a show of hands, the motion passed with four opposed (4 Publicly Owned) and no abstentions.
EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of September 7, 2017

The following activity, as more fully described in the attached litigation report, has occurred since the report dated August 1, 2017 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

2 NEPGA PER Complaint / Settlement Agreement (EL16-120; ER17-2153)
   Aug 16-17 ISO-NE files comments stating that it neither supports nor objects to the proposed PER strike price methodology and requests that the Commission resolve how the Average Monthly Peak Energy Rent will be calculated on and after June 1, 2018; NEPOOL, NEPGA, NESCOE, Eversource file comments supporting Settlement; FERC Trial Staff submits comments stating it did not oppose the Settlement
   Aug 18 Judge Young issues final report anticipating certification of Settlement to Commission
   Aug 28 NEPGA et al., NESCOE file reply comments
   Aug 31 Judge Young certifies uncontested settlement to the FERC; FERC accepts withdrawal of initial filing in favor of filing now pending before the FERC with updated eTariff code
   Sep 6 Chief Judge terminates settlement judge procedures

5 206 Proceeding: RNS/LNS Rates and Rate Protocols (EL16-19)
   Aug 8 Settlement Judge Dring issues report recommending that settlement procedures be continued; 9th settlement conf. scheduled for Sep 22

II. Rate, ICR, FCA, Cost Recovery Filings

7 FCA12 De-List Bids Filing (ER17-2110)
   Aug 7-24 NEPOOL, National Grid, NEPGA, Eversource, PSEG intervene
   Aug 9 Public Citizen protests filing
   Aug 23 FERC issues deficiency letter requiring the ISO to submit a proposed form of a Non-Disclosure Agreement
   Aug 24 NEPGA answers Public Citizen Aug 9 Protest
   Aug 25 ISO-NE answers Public Citizen Aug 9; responds to Aug 23 deficiency letter
   Aug 28 Public Citizen answers ISO-NE’s Aug 25 answer
   Sep 5 ISO-NE answers Public Citizen Aug 28 answer and formally objects to disclosure of public version of Jul 19 filing

8 NESCOE 5-year (2018-2022) Pro Forma Budget (ER17-2062)
   Aug 18 FERC accepts NESCOE’s 5-year pro forma budget covering the 2018-2022 period

9 Opinion 531-A Compliance Filing Undo: TOs (ER15-414)
   Aug 2 CAPs/EMCOS request OEMR’s Director, Division of Electric Power Regulation-East, reject filing under his delegated authority
   Aug 9 TOs’ answer Aug 2 request, asserting no basis to grant request

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

9 PRD: Full Integration Conforming Changes (ER17-2164)
   Aug 16 Direct, Dominion, Eversource, National Grid, Public Citizen intervene

10 Waiver Request: Dispatchable Resources RTU Req. (McCallum/ Derby Dam) (ER17-1615)
   Sep 7 ISO-NE withdraws objection to waiver request, noting Derby Dam, if properly registered as an intermittent generator, would not be subject to Resource Dispatchability rules

11 CONE & ORTP Updates (ER17-795)
   Aug 8 ISO-NE submits filing to re-establish statutory action date (now Oct 7) on its CONE/ORTP updates
### IV. OATT Amendments / TOAs / Coordination Agreements

| * | 14 | Clustering Revisions (ER17-2421) | Sep 1 | ISO-NE, NEPOOL and PTO AC jointly file Clustering Revisions; comment date Sep 22 |
| | | | Sep 6-7 | NESCOE, RENEW intervene |
| | 14 | Tariff Section II.44 Conforming Change (ER17-2118) | Aug 25 | FERC accepts change aligning Tariff Section II.44(1)(a) with the Market Rules’ Day-Ahead Energy Market scheduling deadline, eff. Sep 20 |

### V. Financial Assurance/Billing Policy Amendments

*No Activity to Report*

### VI. Schedule 20/21/22/23 Changes

| 14 | Schedule 21-ES: PSNH/Pontook IA (ER17-2449) | Sep 7 | Eversource files agreement; comment date Sep 28 |
| 14 | Schedule 21-EM: Recovery of Bangor Hydro/Maine Public Service Merger-Related Costs (ER15-1434 et al.) | Sep 6 | 4th settlement conf. held |

### VII. NEPOOL Agreement/Participants Agreement Amendments

| * | 16 | 131st Agreement (Small Standard Offer Service Provider Amendments) (ER17-2425) | Sep 1 | NEPOOL files changes to NEPOOL Agreement to implement Small Standard Offer Service Provider arrangements and increase to Data-Only Participant application fee; comment date Sep 22 |

### VIII. Regional Reports

| | | | Aug 21 | NEPOOL intervenes and files comments on Q2 Report |
| | | | Aug 28-29 | National Grid, Eversource intervene |

### IX. Membership Filings

| * | 17 | September 2017 Membership Filing (ER17-2184) | Sep 1 | New Members: Durgin and Crowell Lumber Co.; Marie’s Way Solar I; Phoenix Energy New England; Syncarpha Lexington; and Tenaska Power Management; and Name Change: Nautilus Power, LLC (f/k/a Essential Power, LLC) |
| 17 | July 2017 Membership Filing (ER17-2039) | Aug 15 | FERC accepts as new members MPower Energy; Renaissance Power & Gas; and Environmental Defense Fund; Brayton Point’s withdrawal |

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

| * | 17 | Revised Rel. Standards (Errata): VAR-001-4.1, VAR-002-4 (RD17-7) | Aug 18 | NERC files revised Standards; comment date Sep 20 |
| * | 18 | Revised VRFs for Reliability Standard BAL-002-2 (RD17-6) | Aug 14 | NERC files revised VRFs; comment date Sep 18 |
* 20 2018 NERC/NPCC Business Plans and Budgets (RR17-7) Aug 23 NERC submits proposed 2018 Business Plan and Budget for itself and its Regional Entities, including NPCC; comment date Sep 13

**XI. Misc. - of Regional Interest**

* 20 203 Application: CPV Towantic/Archmore (EC17-158) Aug 15 CPV Towantic, GE Towantic Holdings and Aircraft Services Corp. request authorization for a transaction by which Archmore International Infrastructure Funds through a wholly-owned indirect sub. will acquire an approx. 11% interest in CPV Towantic Aug 18 Eversource intervenes

* 20 203 Application: GenOn Reorganization (EC17-152) Aug 4 GenOn requests authorization for reorganization that will occur as a result of its bankruptcy chapter 11 restructuring Aug 25 Public Citizen protests, and withdraws protest to, application

21 203 Application: Dynegy (Dighton/Milford)/Marco DM Holdings (EC17-146) Aug 7 Public Citizen intervenes

21 203 Application: NAPG/Mercuria (EC17-144) Aug 9 Public Citizen intervenes


* 22 LCC Agreement: National Grid (ER17-2339) Aug 21 National Grid files LCC Agreement to replace REMVEC II Agreement; comment date Sep 11

* 22 LCC Agreement: NSTAR/Reading (ER17-2324) Aug 18 NSTAR files LCC and Telemetering Services Agreements with Reading; comment date Sep 8

23 D&E Agreement: NSTAR/Essential Power Newington (ER17-1915) Aug 11 FERC accepts agreement, eff. Aug 26

* 25 FERC Enforcement Action: Westar Energy (IN15-8) Aug 24 FERC approves $180,000 civil penalty for Westar Energy violations of the SPP Tariff

* 25 FERC Enforcement Action: ATC (IN17-5) Aug 28 FERC approves $205,000 civil penalty for ATC violations of FPA Sections 203 and 205

* 26 FERC Enforcement Action: City Power Marketing and Tsingas (IN15-5) Aug 22 FERC approves settlement resolving its investigation into (and subsequent litigation in the DC District Court to obtain payments for) City Power Respondents violations of the FERC’s Anti-Manipulation Rules -- City Power to pay a $9 million civil penalty, Tsingas to pay a $1.3 million disgorgement to PJM and a $1.42 million civil penalty, and Tsingas subject to a 3-year prohibition on any connection to or with any FERC jurisdictional trades

**XII. Misc. - Administrative & Rulemaking Proceedings**

29 NOPR: Fast-Start Pricing in RTO/ISO Markets (RM17-3) Aug 18 CAISO files supplemental comments

31 NOPR: Primary Frequency Response - Essential Rel. Services and the Evolving BPS (RM16-6) Aug 18 FERC requests supplemental comments; comment date (as extended) Oct 10 Aug 30 APPA/EEI/NRECA jointly request extension of comment deadline Sep 7 FERC grants motion for extension of comment deadline, now Oct 10

**XIII. Natural Gas Proceedings**

35 New England Pipeline Proceedings Atlantic Bridge Project (CP16-9) Aug 21 FERC denies Weymouth request for stay and denies rehearing of Atlantic Bridge Project Order
### XIV. State Proceedings & Federal Legislative Proceedings

*No Activity Reported*

### XV. Federal Courts

<table>
<thead>
<tr>
<th>Case Description</th>
<th>Date</th>
<th>Details</th>
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</thead>
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<tr>
<td>37 NEPGA PER Complaint and FCM Jump Ball and Compliance Proceedings (16-1023/1024)</td>
<td>Aug 14</td>
<td>Oral argument scheduled for <em>Oct 27, 2017</em> (composition of panel will be identified approx. 30 days in advance of argument)</td>
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</tbody>
</table>
MEMORANDUM

TO: NEPOOL Participants Committee Member and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: September 8, 2017

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”), state regulatory commissions, and the Federal Courts and legislatures through September 7, 2017. If you have questions, please contact us.¹

I. Complaints/Section 206 Proceedings

- **NEPGA PER Complaint / Settlement Agreement (EL16-120; ER17-2153)**
  
  On July 28, 2017,² the Settling Parties³ submitted an Offer of Settlement and settlement materials (“PER Settlement”) to resolve the issue set for hearing and settlement judge procedures by the Commission in this proceeding. Under the PER Settlement, the ISO will calculate Adjusted Hourly Strike Price as the sum of the daily Strike Price (as calculated under the existing Tariff) and a newly-defined Hourly PER Adjustment. The Hourly PER Adjustment will be equal to the average over each hour of a newly-defined Five-Minute PER Strike Price Adjustment. The Five-Minute Strike Price Adjustment⁴ will be equal to any positive difference between a five-minute Thirty Minute Operating Reserves Clearing Price or Ten-Minute Non-Spinning Reserves Clearing Price that exceeds the maximum allowable reserves clearing prices for those reserves products (i.e., the Reserve Constraint Penalty Factors) in effect before December 2014. The PER Settlement does not resolve the issues of the applicability of the Strike Price methodology to FCA9 (which will be subject to comment in response to the PER Settlement Agreement) or whether capacity suppliers will receive any refunds for PER Events that occurred in August 2016 (currently the subject of, and to be decided through, a pending request for clarification and/or rehearing as noted below). Those issues remain to be resolved by the Commission when and as appropriate. The term sheet that formed the basis for the PER Settlement was supported by the Participants Committee at the June 27 session of the Summer Meeting. Initial comments on the PER Settlement were due on or before August 17, 2017; reply comments, August 28,

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 The Settlement was initially filed on July 26 under different eTariff codes and subsequently withdrawn in favor of the July 28 filing. The Docket Number (ER17-2153) remained the same. The withdrawal of the July 26 filing was accepted on August 31.


⁴ Five-Minute PER Strike Price Adjustment will be calculated according to the following formula: Five-Minute PER Strike Price Adjustment = MAX (Thirty Minute Operating Reserves Clearing Price - $500/MWh, 0) + MAX (Ten Minute Non-Spinning Reserves Clearing Price – Thirty Minute Operating Reserves Clearing Price - $850/MWh, 0).
On July 31, Chief Judge Cintron issued an order that, “in the interest of administrative efficiency,” all parties granted intervention in EL16-120 “are deemed to have intervened in Docket No. ER17-2153-000”. On August 16, ISO-NE filed comments stating that it neither supports nor objects to the proposed PER strike price methodology and requested that the Commission resolve how the Average Monthly Peak Energy Rent will be calculated on and after June 1, 2018. Comments supporting the settlement were filed by NEPOOL, NEPGA, NESCOE, and Eversource. FERC Trial Staff submitted comments stating it did not oppose the Settlement. Reply comments were filed on August 28 by NESCOE (asking the FERC to reject the position advocated by NEPGA that the agreed-upon Adjusted Hourly Strike Price as defined in the Settlement should extend beyond May 31, 2018) and jointly by NEPGA, NRG, HQUS, Dominion, and Verso (asking the FERC to approve the Settlement and order ISO-NE to make a compliance filing, but decline to address NESCOE’s request until some later date). On August 31, Judge Young certified the uncontested settlement to the FERC and is now pending before the Commission.

As previously reported, the FERC, on January 19, (i) granted in part NEPGA’s complaint and (ii) set in part for hearing and settlement judge procedures the question of the appropriate method of calculating the PER Strike Price under Market Rule 1 section III.13.7.2.7.1.1.1. In granting NEPGA’s complaint in part, the FERC found that “for the period at issue in NEPGA’s complaint (September 30, 2016 – May 31, 2018), the PER mechanism has become unjust and unreasonable as a result of the interaction between the PER mechanism and the higher Reserve Constraint Penalty Factors.” Accordingly, the FERC required the ISO to revise the method by which it calculates the PER Strike Price as set forth in Tariff section III.13.7.2.7.1.1.1. But, finding NEPGA’s request that the PER Strike Price be increased by $250 per MWh “raises issues of material fact that cannot be resolved based upon the record before us and that are more appropriately addressed in the hearing and settlement judge procedures”, the FERC set the question of for hearing and settlement judge procedures under section 206 of the FPA. The FERC established a refund effective date of September 30, 2016 (the date of the complaint). In establishing a September 30, 2016 effective date, the FERC clarified that “any changes to the calculation of the PER Strike Price under ISO-NE Tariff section III.13.7.2.7.1.1.1 would be prospective only from September 30, 2016, as required by FPA section 206, and would not impact the application of any PER Adjustment occurring before September 30, 2016.” On February 15, NEPGA requested clarification of the PER Complaint Order with respect to the PER Adjustment payments charged to NEPGA’s members on capacity invoices issued after the refund effective date. Specifically, NEPGA asked for clarification that when the FERC “determines refunds, it will direct the ISO to refund to capacity suppliers the difference between: (i) the PER Adjustment payments charged to capacity suppliers after the September 30, 2016 refund effective date, and (ii) the PER Adjustment payments that would have been charged to capacity suppliers if the PER Adjustment were calculated using a just and reasonable PER Strike Price.” On March 3, NESCOE and RESA answered NEPGA’s rehearing request. NEPGA answered those answers on March 17. The FERC issued a tolling order on March 16, 2017, affording it additional time to consider NEPGA’s request for rehearing, which remains pending.

**Settlement Judge Procedures.** As reported previously, Judge H. Peter Young was the Settlement Judge in these proceedings. In his last status report, Judge Young reported that the formal offer of settlement

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5 Prior to Chief Judge Cintron’s order, the following parties filed doc-less interventions in ER17-2153: Calpine, ConEd, Entergy, Eversource, Exelon, HQUS, NEPGA, NESCOE, NRG/GenOn, and RESA.

6 NEPGA’s complaint asked the FERC (i) to find the ISO Tariff’s Peak Energy Rent (“PER”) Adjustment provisions unjust & unreasonable; (ii) to direct the ISO to file revisions to the PER Adjustment sections of the Tariff that return the PER Adjustment to a just & reasonable level; (iii) to establish a refund effective date of September 30, 2016; and (iv) to issue an order granting the complaint by November 29, 2016.


8 Id. at P 48.

9 Id. at P 57.

10 Id. at P 61.
appeared to be uncontested, would comprehensively resolve all issues set for hearing in this proceeding, and would be certified to the Commission before his next report would be due. As noted above, Judge Young certified the uncontested settlement to the Commission on August 31, where it is pending Commission action. There being no additional matters pending before Judge Young, and subject to final action by the Commission, Chief Judge Cintron terminated settlement judge procedures on September 6.

If you have any questions concerning this matter, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com), Jamie Blackburn (202-218-3905; jblackburn@daypitney.com), or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

**Base ROE Complaint IV (2016) (EL16-64)**

On September 20, 2016, the FERC established hearing and settlement judge procedures (and set a refund effective date of April 29, 2016) for the 4th ROE Complaint. As previously reported, EMCOS filed the 4th ROE complaint on April 29, 2016. The 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%. EMCOS identified three main considerations requiring submission of this Complaint: (1) the continuing decline of the market cost of equity capital, which makes NETOS’ currently authorized ROE “excessive, unjust and unreasonable, and therefore ripe for adjustment under FPA Section 206”; (2) “divergent rulings concerning the persistence of the “anomalous” capital market conditions”; and (3) “the extent to which the Commission’s anomalous conditions rationale in Opinion No. 531 is intended to reflect changes in its long-standing reliance on the discounted cash flow (“DCF”) methodology, and particularly the DCF midpoint, for determining ROE remains unclear.”

In setting the complaint for hearing and settlement judge procedures, the FERC found that the Complaint “raises issues of material fact that cannot be resolved based upon the record before us and that are more appropriately addressed in the hearing and settlement judge procedures we order.” The FERC also found “unpersuasive the assertions of New England TOs and EEI that the Commission should dismiss the Complaint because the New England TOs’ base ROE continues to fall within the zone of reasonableness. The Commission has repeatedly rejected the assertion that every ROE within the zone of reasonableness must be treated as an equally just and reasonable ROE.” Further, the FERC rejected arguments as to the propriety of allowing a fourth complaint against the TOs’ ROE after three previous complaints have been filed since 2011. As it did when it allowed Complaints II and III to go forward, the FERC found that Complaint IV was properly set for hearing as it is based on newer, more current data than prior Complaints subsequent hearings. The FERC is “initiating an entirely new proceeding, based on an entirely separate factual record, that may or may not reach the same conclusions as those reached in the earlier ROE proceeding.” The FERC estimated that, if this case does not settle and goes to hearing, the Commission’s ultimate decision would be issued on or before June 30, 2018. Both the TOs and EEI requested rehearing of the Base ROE

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13 *Base ROE Complaint IV Order* at P 37.

14 *Id.* at P 38.

15 Complaint IV was filed 21 months after the July 31, 2014 filing of Complaint III, nearly nine months after the July 2, 2015 close of the Complaint III evidentiary hearing record, and six months after the end of the Complaint III refund period.

16 *Base ROE Complaint IV Order* at P 40.

17 *Id.* at P 44.
Complaint IV Order. The FERC issued a tolling order on November 21, 2016, affording it additional time to consider the requests for rehearing, which remain pending.

Settlement Judge Procedures. On June 27, 2017, Settlement Judge Long recommended termination of settlement judge procedures, reporting that the parties did not appear to be amenable to settlement and had reached an impasse. On June 30, Chief Judge Cintron terminated settlement judge procedures; with hearings to continue as scheduled and reported below.

Hearings. On December 21, 2016, in response to a request of the parties and supported by Settlement Judge Long, Chief Judge Cintron designated Steven A. Glazer as presiding judge for hearings in this matter, so that hearing procedures could proceed concurrently with settlement judge procedures (now terminated). The hearings will be conducted under the FERC’s “Track II” procedural time standards, which requires that an initial decision be issued within 47 weeks, or by November 15, 2017. Direct and Answering Testimony and Exhibits have been filed. Hearings are scheduled for August 2-8, with an initial decision to be issued on or before November 15, 2017.

Oral argument, conducted on May 18, 2017 en banc before Chief Judge Cintron and Presiding Judge Glazer, addressed the impacts of the DC Circuit’s April 14, 2017 Emera Maine decision on the Base ROE Complaint I orders (see Section XV below). At the conclusion of the May 18 en banc oral argument, Chief Judge Cintron ruled from the bench that (i) the request to hold this proceeding in abeyance or recommend to the Commission that it be dismissed was denied, (ii) the proceeding would continue pursuant to a revised procedural schedule, and (iii) the participants were to submit by May 25, 2017, a revised procedural schedule consistent with the sequencing proposed by the TOs Answer and Motion. She confirmed those rulings in a May 26 order, which also adopted a revised procedural schedule. On June 12, the TOs moved for reconsideration of the May 26 order, or in the alternative, that the Chief Judge grant the NETOs’ request to seek an interlocutory appeal of the May 26 order. The TOs’ motion was challenged by Complainants. On June 29, the Chief Judge denied the June 12 motion. On July 5, the TOs sought interlocutory appeal of the Chief Judge’s June 29 order, which Complainants opposed, and Chairman LaFleur, acting as motions Commissioner, declined to refer to the full Commission. On July 31, 2017, the TOs filed Supplemental Answering Testimony and Exhibits (with summaries).

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).

- 206 Proceeding: RNS/LNS Rates and Rate Protocols (EL16-19)
  Settlement discussions in this proceeding are on-going. As previously reported, the FERC instituted this Section 206 proceeding on December 28, 2015, finding that the ISO Tariff is 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”).\(^{18}\) 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”.\(^{19}\) Accordingly, the FERC established hearing and settlement judge procedures to develop just and reasonable formula rate protocols to be included in the ISO-NE Tariff and to examine the justness and reasonableness of the RNS and LNS rates. The FERC encouraged the parties to make every effort to settle this matter before hearing procedures


\(^{19}\) Id. at P 8.
are commenced.\textsuperscript{20} Hearings are being held in abeyance pending the outcome of settlement judge procedures underway.\textsuperscript{21} The FERC-established refund date is January 4, 2016.\textsuperscript{22}

**Settlement Judge Procedures.** As previously reported, John P. Dring was designated the Settlement Judge in these proceedings. Five settlement conferences were held in 2016: January 19, March 24, April 28, August 30, and November 18 (telephonically). Three settlement conferences have thus far been held in 2017: April 5, May 9 and July 7, 2017. A ninth settlement conference has been scheduled for September 22, 2017. Judge Dring’s most recent status report was issued on August 8, noting that the proceeding is taking longer than expected but that the parties are making progress toward settlement. Accordingly, he recommended that the settlement procedures be continued. The Transmission Committee is being kept apprised, as appropriate, of settlement efforts. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Base ROE Complaints II & III (2012 & 2014) (EL13-33 and EL14-86) (consolidated)**
  
  Judge Sterner’s findings and Initial Decision, and pleadings in response thereto, remain pending before the FERC. As previously reported, the FERC, in response to second (EL13-33)\textsuperscript{23} and third (EL14-86)\textsuperscript{24} complaints regarding the TOs’ 11.14% Base ROE, issued orders establishing trial-type, evidentiary hearings and separate refund periods. The first, in EL13-33, was issued on June 19, 2014 and established a 15-month refund period of December 27, 2012 through March 27, 2014;\textsuperscript{25} the second, in EL14-86, was issued on November 24, 2014, established a 15-month refund period beginning July 31, 2014, and, because of “common issues of law and fact”, consolidated the two proceedings for purposes of hearing and decision, with the FERC finding it “appropriate for the parties to litigate a separate ROE for each refund period.”\textsuperscript{26} The TOs requested rehearing of both orders. On May 14, 2015, the FERC denied rehearing of both orders.\textsuperscript{28} On July 13, 2015, the TOs appealed those orders to the DC Circuit Court of Appeals (see Section XIV below), and that appeal remains pending.

**Hearings and Trial Judge Initial Decision.** Initial hearings on these matters were completed on July 2, 2015. In mid-December 2015, Judge Sterner reopened the record for the limited purpose of having the

\textsuperscript{20} Id. at P 11.

\textsuperscript{21} Id.

\textsuperscript{22} The notice of this proceeding was published in the *Fed. Reg.* on Jan. 4, 2016 (Vol. 81, No. 1) p. 89.

\textsuperscript{23} 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%.

\textsuperscript{24} 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.


\textsuperscript{26} Mass. Att’y Gen. et al. -v- Bangor Hydro et al., 149 FERC ¶ 61,156 (Nov. 24, 2014), reh’g denied, 151 FERC ¶ 61,125 (May 14, 2015).

\textsuperscript{27} Id. at P 27 (for the refund period covered by EL13-33 (i.e., Dec. 27, 2012 through Mar. 27, 2014), the ROE for that particular 15-month refund period should be based on the last six months of that period; the refund period in EL14-86 and for the prospective period, on the most recent financial data in the record).

DCF calculations re-run in accordance with the FERC’s preferred approach and re-submitted. A limited hearing on that supplemental information was held on February 1, 2016. On March 22, 2016, Judge Sterner issued his 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. The Decision also lowered the ROE ceilings. Judge Sterner’s decision, if upheld by the FERC, would result in refunds totaling as much as $100 million, largely concentrated in the EL13-33 refund period. Briefs on exceptions were filed by the TOs, Complainant-Aligned Parties (“CAPs”), EMCOS, and FERC Trial Staff on April 21, 2016; briefs opposing exceptions, on May 20, 2016. Judge Sterner’s findings and Initial Decision, and pleadings in response thereto, remain pending, and will be subject to challenge, before the FERC. The 2012/14 ROE Initial Decision and its findings can be approved or rejected, in whole or in part.

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).

II. Rate, ICR, FCA, Cost Recovery Filings

- **FCA12 De-List Bids Filing (ER17-2110)**

  Pursuant to Market Rule 1 § 13.8.1(a), the ISO submitted on July 19 a filing describing the Permanent De-List Bids and Retirement De-List Bids that were submitted on or prior to the FCA12 Existing Capacity Retirement Deadline. The ISO reported that the Existing Capacity Retirement Deadline for FCA12 was March 24, 2017 and it received one Permanent De-List and 23 Retirement De-List Bids for resources located in each of the eight Load Zones, with an aggregate MWs of capacity of 511.104 MWs. Four of the 24 Bids were for resources under 20 MW, and from four suppliers that were not Affiliates of the remaining two suppliers that submitted the remaining 20 bids. The IMM was not required to perform a review of those 4 bids. The IMM did review the remaining two suppliers’ 20 Bids for 502.579 MWs of capacity. The IMM’s determination regarding these 20 bids is described in the version of the filing that was filed confidentially as required under §13.8.1(a) of Market Rule 1. Comments on this filing are due on or before August 9. Public Citizen filed a protest on the basis that, absent Commission direction, it would not have an opportunity to obtain access to the privileged components of the filing. Specifically, Public Citizen requested, subject to execution of a Non-Disclosure Agreement, access to: (i) the IMM’s determination with respect to each Permanent De-List Bid and Retirement De-List Bid, (ii) supporting documentation for each determination, (iii) “the capacity that will permanently de-list or retire prior to the Forward Capacity Auction”, and (iv) whether capacity suppliers that submitted the bids have elected to conditionally or unconditionally retire the capacity.

  The July 19 filing was protested on August 9 by Public Citizen, which complained that it is unable to determine the just and reasonableness of the De-List Bids due to a lack of access to the privileged components of the filing. Public Citizen requested access, subject to a Non-Disclosure Agreement, to: (i) the IMM’s documentation and determinations with respect to each De-List Bid and Retirement De-List Bid, (ii) information as to the capacity that will permanently de-list or retire prior to FCA12 and whether any retirement elections were conditional or unconditional. Answers to Public Citizen’s protest and objections to disclosure of any non-public information filed in the proceeding were filed by the ISO and NEPGA, with the ISO indicating that it would not disclose the non-public information to Public Citizen absent a FERC order. Doc-less interventions were filed by NEPOOL, National Grid, and out-of-time by Eversource, NEPGA and PSEG. Public Citizen answered the ISO’s answer on August 28. The ISO answered Public Citizen’s August 28 answer on September 5.

  **Deficiency Letter.** On August 23, the FERC issued a letter indicating that the ISO’s filing was insufficient because it did not include, as required per FERC regulations, a proposed form of a Non-Disclosure Agreement (“NDA”) pursuant to which participants or intervenors in the proceeding could request a copy of the

complete non-public version of the filing.\textsuperscript{30} If an objection to the disclosure of the requested non-public information is filed, disclosure of the information need only be made if so ordered by the FERC. In response, on August 25, the ISO requested waiver of the FERC requirement, given prior FERC rulings on substantively indistinguishable, competitively sensitive and confidential market data in FCA8-related proceedings.\textsuperscript{31} The ISO also submitted a form of NDA to comply with the August 23 letter, doing so without prejudice to its position that none of the confidential portions of the De-List Bids Filing should be disclosed to any intervenor even under a NDA. The ISO’s response to the deficiency re-set the statutory action deadline in this proceeding to October 24. On September 5, the ISO filed a formal objection to the disclosure of the non-public version of its filing. Other than Public Citizen, no additional parties requested access to the non-public version of the filing, which absent FERC order will not be provided.

These matters are pending before the FERC. If you have any questions, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **NEESCO 5-year (2018-2022) Pro Forma Budget (ER17-2062)**
  On August 18, 2017, the FERC accepted NESCOE’s 5-year pro forma budget covering years 2018 - 2022 (the “5-year Pro Forma Budget”). Annual NESCOE budgets will continue to be reviewed on roughly the same schedule as the ISO’s annual budgets. Unless the August 18 order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Exelon Request for Additional Cost Recovery (ER17-933)**
  As previously reported, the Director of Office of Energy Market Regulation (“OEMR”)-East, pursuant to the FERC’s February 3 Absence of a Quorum Delegation Order,\textsuperscript{32} issued an order on March 30, 2017, accepting Exelon’s Cost Recovery Filing for filing, suspended for a nominal period, to become effective March 30, 2017, subject to refund and further Commission order. As a practical matter, however, the letter order merely punted to a later date a final FERC decision on this matter. The letter order stated that “preliminary analysis indicates that Exelon’s filing has not been shown to be just and reasonable and may be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful … Protests and comments will be addressed in a further Commission order as appropriate.”

Recall that, on February 3, pursuant to Section III.A.15 of Appendix A to Market Rule 1,\textsuperscript{33} Exelon Generation Company (“Exelon”) requested that the FERC authorize recovery of $1,495,171 of actual fuel costs for Mystic Generating Station Units 8 and 9 (“Mystic 8 and 9”) that were not recovered due to market power mitigation applied during the months of October and November 2016, as well as associated regulatory costs (estimated by Exelon to be roughly $60,000). Comments on Exelon’s request were due on or before February 24. The ISO answered the Exelon request on February 24, requesting that the FERC “reject [Exelon]’s request for additional cost recovery for October 1, 3 and 4, and, to the extent it accepts the remainder of [Exelon]’s Cost Recovery Request, affirm that the amount recovered is justified by the IMM’s correct application of the ISO Tariff provisions for calculating cost-based Reference Levels.” On March 13, Exelon and NEPGA (which also moved to intervene out-of-time) answered the ISO’s February 24 answer. Exelon asked that the FERC strike the portions of the IMM’s pleading related to issues Exelon is not seeking/ contesting -- Exelon’s recovery of additional fuel costs incurred under a Shoulder Period Agreement with


\textsuperscript{33} Under Appendix A Section III.A.15, a Market Participant has the right to make a Section 205 filing seeking additional cost recovery if, as a result of mitigation applied under Appendix A or the Energy Offer Cap, it will not recover the fuel and variable operating and maintenance (“O&M”) costs of a Resource for all or part of one or more Operating Days.
ENGIE and the IMM’s request that the FERC “find that the IMM has properly applied the ISO Tariff in establishing the Reference Levels for the Mystic 8 and 9 units . . . .” NEPGA, which also moved to intervene out-of-time, also asked the FERC to deny the IMM’s requested Reference Level finding. Additional parties to the proceeding include NEPOOL and Direct Energy Business. On March 29, the IMM responded to the March 13 Exelon and NEPGA answers.

This matter remains subject to further FERC proceedings and/or action. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **TOs Opinion 531-A Compliance Filing Undo (ER15-414-002)**
  As previously reported, the TOs submitted, on June 5, 2017, tariff changes (to both the regional and local rates in the ISO OATT) to document the reinstatement of their transmission rates under the OATT to the status quo ante as a result of the DC Circuit’s mandate in Emera Maine v. FERC, Case No. 15-118 et al. (“June 5 Filing”). While the TOs asked for a June 6, 2017 effective date, the TOs also stated that they do not intend to commence billing under the reinstated rates until 60 days after the FERC has a quorum (now known to be October 9, 2017). On June 26, both EMCos and Consumer Aligned Parties (“CAPs”) protested the June 5 Filing. On July 11, the TOs answered those protests. On August 2, CAPs and EMCos requested that, in light of concerns that New England transmission customers will be subject to increased charges before the FERC is able to act on this matter, the Director of OEMR’s Division of Electric Power Regulation East exercise his delegated authority and reject the June 5 Filing. On August 9, the TOs answered the August 2 CAPs/EMCos request, asserting that there was no basis to grant their request for rejection of the June 5 Filing. No action in response to the August 2 request has been taken and this matter remains pending before the FERC. 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).

- **2017/18 Power Year Transmission Rate Filing (ER09-1532; RT04-2)**
  On July 28, 2017, the Participating Transmission Owners (“PTOs”) Administrative Committee (“PTO AC”) submitted a filing identifying adjustments to regional transmission service charges under Section II of the ISO Tariff for the period June 1, 2017 through May 31, 2018. The filing reflected the charges to be assessed under annual transmission formula rates, reflecting actual 2016 cost data, Forecasted Annual Transmission Revenue Requirements associated with projected PTF additions for the 2017 Forecast Period, and the Annual True-up including associated interest. The PTO AC states that the annual updates results in a Pool “postage stamp” RNS Rate of $111.96/kW-year effective June 1, 2017, an increase of $7.86/kW-year from the charges that went into effect on June 1, 2016. In addition, the annual update to the Schedule 1 formula rate results in a charge of $1.81 kW-year, a $0.01/kW-year increase over the Schedule 1 charge that last went into effect on June 1, 2016. This filing was reviewed at the July 18 session of the Reliability/Transmission Committee summer meeting. The filing was not noticed for public comment. If there are questions on this proceeding, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

- **PRD: Full Integration Conforming Changes (ER17-2164)**
  On July 27, 2017, the ISO and NEPOOL jointly filed a final package of Tariff revisions required to implement the full integration of price-responsive demand (“PRD”) into New England’s Energy, Ancillary Services, and capacity markets on June 1, 2018 (“PRD Revisions”). Accordingly, a June 1, 2018 effective date was requested. The PRD Revisions were supported unanimously by the Participants Committee at the Summer Meeting’s June 27 session (Item #8). Comments on this filing were due on or before August 17; none were filed. Doc-less interventions were filed by NRG, Direct, Dominion, Eversource, National Grid, and Public Citizen.

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34 CAPs are: the state utility commissions of Connecticut, Massachusetts, and New Hampshire; the Rhode Island Division of Public Utilities and Carriers (“RIPUC”); the Connecticut and Massachusetts Attorneys General; CT OCC; MOPA; NHOCA; MMWEC; NHEC; IECG; and AIM.
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).

- **Waiver Request: Dispatchable Resources RTU Requirement (McCallum Enterprises) (ER17-1615)**

  On May 9, McCallum Enterprises, owner of the 7 MW Derby Hydroelectric Project in Shelton and Derby, Connecticut, asked the FERC for a waiver of the portion of Market Rule Section 1.11.3 that requires McCallum to install a remote terminal unit (“RTU”) and the necessary circuitry to make the Derby Project electronically dispatchable (“Waiver Request”). McCallum asserts that, based on the specific facts related to the Derby Project, it is both unreasonable and unnecessary for it to be required to incur the expenses associated with an RTU and 24x7x365 staff monitoring. It asks that it be allowed to continue to utilize a telephone-based dispatch system. On May 31, the ISO opposed the Waiver Request. In opposing the request, the ISO asserted that McCallum has at least two other available options to meet the Resource Dispatchability Requirements, the Waiver Request is contrary to both the price formation and reliability objectives of the Resource Dispatchability Rules, would provide an unjustified preference over similarly situated resources, and would not be consistent with OP-14 requirements that a Designated Entity be available 24x7x365 to receive dispatch instructions. CL&P, which is the Lead Market Participant for the Project, intervened and asked that it “not be held liable for compliance with the market rule should the waiver request be declined.” In a June 12 answer, the ISO opposed CL&P’s request, noting that, “as the Lead Market Participant for the Derby Dam facility, and under the terms of the Market Participant Service Agreement executed by it, CL&P is responsible for compliance with all ISO-NE Tariff requirements applicable to the Derby Dam facility—including compliance with the new Resource Dispatchability rules.” McCallum answered the ISO’s protest on June 9, re-iterating its points made in the initial May 9 request, and the ISO’s answer to CL&P’s motion on June 22.

  On September 7, the ISO withdrew its opposition to the McCallum Waiver Request. The ISO stated that, based on McCallum statements in its June 9 answer (which indicated that McCallum’s generator does not have control over its output because its operation is wholly subject to the operation of an upstream dam facility), and after further investigation, the ISO has subsequently determined that the Derby Dam facility is improperly registered as a non-intermittent generator, and that it should instead be registered as an intermittent generator. If properly registered as an intermittent generator, the Derby Dam Facility would not in fact be subject to the Resource Dispatchability rules. The ISO added that it is undertaking efforts to require the resource to re-register as an intermittent generator, and to evaluate whether it should be subject to other dispatch rules when so registered. McCallum’s Waiver Request remains pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pgerity@daypitney.com).

- **Order 831 (Modified Energy Market Offer Caps) Revisions (ER17-1565)**

  Tariff changes in response to the requirements of Order 831 (“Order 831 Revisions”) jointly filed by the ISO and NEPOOL on May 8, 2017 remain pending. As previously reported, the Order 831 Revisions cap incremental energy offers at the higher of $1,000/MWh or a resource’s verified cost-based incremental energy offer (with a hard cap of $2,000/MWh on incremental energy offers used in pricing calculations), provide for make whole payments to recover costs that cannot be verified until after the offer clears and the resource is dispatched, and apply offer cap requirements on a resource-neutral basis. In addition, the Order 831 Revisions include a number of ancillary changes required in order for the offer capping rules to function seamlessly within the market or that are needed because of their relationship to the offer capping rules. An October 1, 2019 effective date was requested (which the ISO stated accounts for the time required to design, develop, implement and test the software and process changes required to implement the Order 831 Revisions and the need to complete other high-priority projects ahead of the development of Order 831 Revision-implementing software changes). The Order 831 Revisions were supported unanimously by the Participants Committee by way of the May 5 Consent Agenda (Item #1). Comments on this filing were due on or before May 30; none were filed. Doc-less interventions were filed by ConEd, Dominion, EPSA, National Grid, and NRG. 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).
CONE & ORTP Updates (ER17-795)

The ISO’s January 13, 2017 filing of updated FCM Cost of New Entry (“CONE”), Net CONE and Offer Review Trigger Price (“ORTP”) values remains before the FERC, awaiting a FERC quorum and an ISO-NE amendment-type filing re-starting the 60-day statutory clock. With respect to CONE and Net CONE, the ISO will use a gas-fired simple cycle combustion-turbine (“CT”) as the reference technology for the updated values, $11.35 and $8.04, respectively. The ISO will use a Capacity factor of 32%, resulting in a $11.02 ORTP for on-shore wind resources. The ISO requested a March 15, 2017 effective date for the new values to coincide with the beginning of the administrative cycle for FCA12. The CONE & ORTP Updates were not supported by the Participants Committee when considered at the January 6 meeting. Comments on this filing were due on or before February 3. Doc-less interventions were filed by Avangrid, Brookfield, Calpine, ConEd, Dominion, Eversource, Exelon, FirstLight, LS Power, National Grid, NextEra, NRG, PSEG, and Cogentrix 35 (out-of-time). Comments were filed by NEPOOL (identifying concerns and alternatives presented and reviewed in the course of the stakeholder process preceding the filing) and NESCOE (supporting the CONE/Net CONE values as overall reasonable updates reflecting changed market outcomes and market designs). NEPGA filed a protest (challenging the ISO’s proposal to base Net CONE for FCA12 on a greenfield simple-cycle combustion turbine). The ISO answered the NEPGA protest on February 17. NEPGA answered the ISO’s February 17 answer on March 6 and the ISO answered NEPGA’s March 6 answer on March 21.

Amendment-Type Filing Deferring Statutory Deadline. On March 6, the ISO submitted, in light of the contested nature of this proceeding and the lack of a FERC quorum, an amendment-type filing to extend indefinitely the date by which the FERC would otherwise have been required to act on the January 13 filing or have the filing become effective by operation of law. The ISO committed to submit a further amendment-type filing, triggering a new 60-day statutory action date, “at the appropriate time” (presumably once the FERC has a quorum). In the meantime, the ISO stated that the proposed March 15, 2017 effective date for the CONE and ORTP Updates remains unchanged and will be used for the administration of FCA12. Comments on the ISO’s March 6 filing were due on or before March 27. NEPOOL filed limited comments seeking acknowledgement in any final order that the ISO’s actions not be construed to have any precedential effect in future contested Section 205 proceedings where the FERC does have a quorum.

Amendment-Type Filing Re-Establishing Statutory Deadline. On August 8, the ISO submitted an amendment-type filing to re-establish the date (now October 7) by which the FERC must act on the January 13 filing or have the filing become effective by operation of law. As previously noted, the proposed March 15, 2017 effective date for the CONE and ORTP Updates remains unchanged and has been used for the administration of FCA12. Comments on the August 8 filing were due on or before August 29; none were filed.

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

FCM Enhancements (ER16-2451)

The FERC’s FCM Enhancements Order 36 remains subject to a request for rehearing by Indicated NYTOs. 37 As previously reported, the FERC accepted changes to the Tariff to increase liquidity in the FCM by increasing Market Participant opportunities to enter into reconfiguration auctions and bilateral contracts for the exchange of CSOs (“FCM Enhancements”). Specifically, the FCM Enhancements (i) modify certain

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35 Cogentrix Energy Power Management, LLC (“Cogentrix”) intervened on behalf of its Participant affiliates Rhode Island State Energy Center, LP, Essential Power Newington, LLC, and Essential Power Massachusetts.


37 “Indicated NYTOs” are Central Hudson Gas & Electric, Consolidated Edison Co. of New York, New York Power Authority, New York State Electric & Gas, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric.
FCM qualification rules to facilitate the ability of New Capacity Resources to supply capacity beginning four months after participating in their first FCA; (ii) provide Import Capacity Resources backed by one or more External Resources the opportunity (currently available to generators and demand response) to provide capacity beginning one or two years after participating in their first FCA; and (iii) establish a new form of bilateral contracting in which Market Participants can, as the Capacity Commitment Period approaches, trade CSOs for a seasonal strip of CSOs. The FCM Enhancements included several smaller improvements as well, including the elimination of a requirement that the ISO make a FERC filing in order to terminate the CSO of a resource that has voluntary withdrawn from the FCM resource development process. The FCM Enhancements were accepted, effective as of October 19, 2016, as requested.

In accepting the FCM Enhancements, the FERC noted that “protestors do not challenge the justness and reasonableness of the specific tariff revisions … the concerns raised by NYISO are not the result of ISO-NE’s proposed tariff revisions, but result from NYISO’s treatment of generators that export capacity from within a constrained locality under its current market rules.” Accordingly, the FERC was “not persuaded that the potential behavior of New York suppliers provides a sufficient basis to reject ISO-NE’s filing in this case, and deferring the effective date of an otherwise just and reasonable proposal would be inconsistent with the notice provision in section 205 of the FPA.” The FERC did acknowledge NYISO’s concerns about a potential flaw in its market rules, and encouraged NYISO stakeholders to timely complete discussions underway to address that flaw.

As noted above, on November 17, 2016, Indicated TOs’ requested rehearing of the FCM Enhancements Order. On December 19, 2016, the FERC issued a tolling order affording it additional time to consider Indicated TOs’ rehearing request, which remains pending before the FERC.

**NYISO Tariff Revisions in Response to FCM Enhancements (ER17-446).** Rehearing remains pending of the FERC’s January 27, 2017 order conditionally accepting in part, and rejecting, in part, NYISO tariff revisions proposed in response to the acceptance of the FCM Enhancements, to correct a pricing inefficiency in NYISO’s Installed Capacity (“ICAP”) market design related to capacity exports from certain zones in the New York Control Area. The order accepted NYISO’s proposed locality exchange factor methodology to be implemented immediately but rejected NYISO’s proposed one-year transitional mechanism. In accepting the immediate implementation of NYISO’s Locality Exchange Factor methodology, the FERC found the proposed methodology “just and reasonable because it corrects a pricing inefficiency in NYISO’s ICAP market design. NYISO’s proposed methodology will now recognize that an exporting generator continues to operate within its Locality, which would be reflected in the ICAP Spot Market Auction clearing prices by accounting for the portion of exported capacity that can be replaced by capacity located in Rest of State. Therefore, NYISO’s proposal will ensure that prices within the Localities reflect actual market conditions and prices.” In rejecting the transition mechanism, the FERC found that “that the mechanism lacks analytical basis and will delay efficient market signals … because it could overstate the extent to which the capacity export will unencumber NYISO’s transmission capability into Southeast New York.” NYISO was directed to submit, and submitted on February 6 and corrected on February 10, a compliance filing removing the one-year transition mechanism provisions. NRG requested rehearing of the January 27 order on February 24. The FERC issued a tolling order on March 27, 2017,

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38 Id. at P 31.
39 Id.
41 Id. at P 20.
42 Id. at P 35.
43 Id. at P 55.
44 Id. at P 61.
affording it additional time to consider NRG’s request for rehearing, which remains pending before the FERC.

If you have any questions concerning these proceedings, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **FCM Resource Retirement Reforms (ER16-551)**

  The NEGPA, NextEra and Exelon request for rehearing of the FERC’s *Resource Retirement Reforms Order*\(^{45}\) remains pending. As previously reported, the FERC conditionally accepted, effective March 1, 2016, changes to the FCM rules for resource retirements proposed by the ISO and its Internal Market Monitor (“IMM”) (the “ISO/IMM Proposal”). The FERC conditioned its acceptance of the ISO/IMM Proposal on the filing of Tariff revisions “establishing a materiality threshold for determining whether or not a particular proxy de-list bid will replace a Retirement Bid in an FCA,”\(^{46}\) which were filed with and later accepted by the FERC.\(^{47}\) NEPGA, Exelon and NextEra jointly requested rehearing of the *Resource Retirement Reforms Order*. On June 13, 2016, the FERC issued a tolling order affording it additional time to consider the joint rehearing request, which remains pending before the FERC. If you have any questions concerning this matter, 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 the ISO’s compliance filing in response to the FERC’s August 8, 2016 remand order.\(^{48}\) In the *2013/14 Winter Reliability Program Remand Order*, the FERC directed the ISO 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 the ISO’s recommendation as to the reasonableness of the bids, so that the FERC can further consider the question of whether the Bid Results were just and reasonable.\(^{49}\) The ISO 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, the ISO 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 the ISO’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

\(^{45}\) ISO New England Inc., 155 FERC ¶ 61,029 (Apr. 12, 2016), reh’g requested (“*Resource Retirement Reforms Order*”). As previously reported, the ISO/IMM Proposal requires (i) that capacity suppliers with existing resources to submit a price for the retirement of a resource (to replace the existing Non-Price Retirement Request process), (ii) the use of a Proxy De-List Bid, and (iii) notice of the potential retirement and proposed retirement price to be submitted prior to the commencement of an FCA’s qualification process for new resources. The ISO/IMM Proposal was considered but not supported by the Participants Committee at its Dec. 4, 2015 meeting.

\(^{46}\) Id. at P 62.


\(^{48}\) 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).

\(^{49}\) 2013/14 Winter Reliability Program Remand Order at P 17.
February 28, the ISO answered the TransCanada and MA AG protests. On March 10, TransCanada answered the ISO’s February 28 answer. This matter is again 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

- **Clustering Revisions (ER17-2421)**
  On September 1, the ISO, NEPOOL and the PTO AC on behalf of the TOs jointly filed changes to the ISO Tariff to incorporate a cluster-based methodology for considering Interconnection Requests and allocating interconnection upgrade costs when a specified set of conditions are present in the interconnection queue (“Clustering Revisions”). A November 1, 2017 effective date was requested. The Clustering Revisions were supported by the Participants Committee at the February 3, 2017 Participants Committee meeting. Comments on this filing are due on or before September 22. Thus far, doc-less interventions were filed by NESCOE and RENEW. If you have any questions concerning this proceeding, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Tariff Section II.44 Conforming Change (ER17-2118)**
  On August 25, the FERC accepted the change that aligns Tariff Section II.44(1)(a) with the Market Rules’ Day-Ahead Energy Market scheduling deadline. The Tariff change was accepted effective as of September 20, 2017. Unless the August 25 order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Changes

- **Schedule 21-ES: PSNH/Pontook IA (ER17-2449)**
  On September 7, 2017, Eversource, on behalf of PSNH, filed a two-party IA between PSNH and Pontook for the continued provision of interconnection service to Pontook’s existing 3-unit, 9.6 MW hydroelectric facility located on the Androscoggin River in Dummer, New Hampshire. The facility has been connected to PSNH distribution system since 1986, Pontook makes use of PSNH’s distribution system and the New England transmission system to market the output of the facility, and the IA replaces a 1985 Agreement whose initial 3-year term has expired. Because there was no modification to the facility or to the interconnection facilities, a three-way IA between PSNH, Pontook and ISO-NE under Schedule 23 of the ISO-NE OATT was not required. A December 16, 2016 effective date was requested. Comments on this filing are due on or before September 28, 2017. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-EM: Recovery of Bangor Hydro/Maine Public Service Merger-Related Costs (ER15-1434 et al.)**
  On June 2, 2016, the FERC accepted, but established hearing and settlement judge procedures for, March 31 filings by Emera Maine in which Emera Maine sought 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”). As previously reported, 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 its recent 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

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50 Emera Maine and BHE Holdings, 155 FERC ¶ 61,230 (June 2, 2016) (“June 2 Order”).
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.

In the June 2 Order, the FERC found that the Compliance Filings raise issues of material fact that could not be resolved based on the record, and are more appropriately addressed in the hearing and settlement judge procedures.51 The FERC reiterated several points with respect to transaction-related cost recovery explained in prior FERC orders and provided guidance on other transaction-related cost recovery points.52 The FERC encouraged the parties to make every effort to settle their disputes before hearing procedures are commenced, and will hold the hearing in abeyance pending the outcome of settlement judge procedures.53 The separate compliance filing dockets were consolidated for the purposes of settlement, hearing and decision.54

**Settlement Judge Procedures.** ALJ John Dring is the settlement judge for these proceedings. There have been three settlement conferences: June 29, October 25, and December 1, 2016. A fourth settlement conference was held on September 6. In a July 26 status report, Judge Dring indicated that, although his previous report indicated that the parties had reached a settlement in principal, the parties informed him that that settlement would not cover this proceeding. Nonetheless, Judge Dring found that the parties are making progress towards settlement, and recommended that settlement procedures be continued. If you have any questions concerning these matters, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-FG&E Annual Informational Filing (ER09-1498)**
  On July 25, 2017 Fitchburg Gas & Electric (“FG&E”) submitted its data and schedules used to calculate its annual transmission revenue requirement for Non-PTF Local Network Transmission Service, Firm Point-to-Point Transmission Service and Non-Firm Point-to-Point Transmission Service as set forth in Schedule 21-FG&E covering the June 1, 2017–May 31, 2018 period. FG&E reported that its annual revenue requirement reflected in FG&E’s rates effective June 1, 2017, is $1,491,456. 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 CWIP Supplement (ER09-1243; ER07-549)**
  On June 30, 2017, NSTAR supplemented its May 31 annual informational filing with a “CWIP Supplement” in accordance with Section 4.1(i) and (ix) of Schedule 21-NSTAR as added and supplemented by Article 4.2 of the 2008 Settlement. The CWIP Supplement was provided primarily on a project-specific basis, and included NSTAR’s 2017 long-range construction forecast. The FERC will not notice this filing for public comment, and absent further activity, no further FERC action is expected. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-CMP Annual Informational Filing (ER09-938)**
  On June 29, CMP submitted its annual update to the formula rates contained in Schedule 21-CMP. CMP indicated that the informational filing reflected actual cost data for the 2016 calendar year plus estimated cost data for the 2017 calendar year associated with CMP’s forecasted transmission plant additions and MPRP CWIP as well as the annual true-up and associated interest. CMP referred to Section 10.2 of Schedule 21-CMP for specific procedures for review and challenges to the informational report. 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).

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51 *Id.* at P 24.
52 *Id.* at PP 25-26.
53 *Id.* at P 27.
54 *Id.* at P 21; Ordering Paragraph (B).
VII. NEPOOL Agreement/Participants Agreement Amendments

- **131st Agreement (ER17-2425)**
  On September 1, 2017, NEPOOL filed changes that implement the Small Standard Offer Service Provider arrangements. The Amendments allow Entities, which exclusively serve a “small” amount of standard offer load (an average hourly aggregate RTLO of 10 MWh or less) the option to have a limited voting share and to make a limited contribution to Participant Expenses until such time as their business grows to the point where they no longer qualify as “small”. A September 1, 2017 effective date was requested. Comments on this filing are due on or before September 22. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VIII. Regional Reports

- **Capital Projects Report - 2017 Q2 (ER17-2289)**
  On August 11, the ISO filed its Capital Projects Report and Unamortized Cost Schedule covering the second quarter (“Q2”) of calendar year 2017 (the “Report”). The ISO is required to file the Report under Section 205 of the FPA pursuant to Section IV.B.6.2 of the Tariff. Report highlights include the following new projects: (i) Price Responsive Demand (“PRD”) ($9,579,200); (ii) IMM Data Analysis Phase I ($1,281,900); (iii) Data Archival & Storage ($683,000); and (iv) Operations Document Management System ($300,000). Projects with significant changes (decreases reallocated to 2018) included: (i) FCM Improvements ($1 million decrease; $300,000 reallocated to 2018); 2017 Issue Resolution Phase II ($600,000 decrease); (iii) Forward Capacity Tracking System (“FCTS”) Technical Architecture Upgrade ($476,800 decrease); (iv) Situational Awareness – Video Wall Expansion Phase II ($834,000 decrease); (v) Balance of Planning Period (“BoPP”) Financial Assurance Project ($141,700 decrease); (vi) Streamlining Asset Registration – Relationship Management ($75,000 decrease); and (vii) Energy Management System (“EMS”) Alarm Presentation Enhancements ($62,000 decrease). Comments on this filing were due on or before September 1. NEPOOL filed comments on the Q2 Report on August 21. Doc-less interventions were filed by National Grid and Eversource. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **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 the ISO in compliance with Opinions No. 531-A and 531-B also remains pending. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Opinions 531-A/531-B Local Refund Reports (EL11-66)**
  The Opinions 531-A and 531-B refund reports filed by the following TOs for their customers taking local service during the refund period also remain pending before the FERC:

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

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

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• **IMM Quarterly Markets Reports - 2017 Spring (ZZ17-4)**
  On August 4, the Internal Market Monitor (“IMM”) filed with the FERC its report for the Spring quarter (Mar 2017 – May 2017) of “market data regularly collected by [it] 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. The Spring Report was discussed with Participants at the August Markets Committee Summer meeting. These filings are not noticed for public comment by the FERC.

• **ISO-NE FERC Form 3Q (2017/Q2) (not docketed)**
  On August 28, the ISO submitted its 2017/Q2 FERC Form 3Q (Quarterly financial report of electric utilities, licensees, and natural gas companies). FERC Form 3-Q is a quarterly regulatory requirement which supplements the annual FERC Form 1 financial reporting requirement. These filings are not noticed for comment.

### IX. Membership Filings

• **September 2017 Membership Filing (ER17-2405)**
  On August 31, NEPOOL requested that the FERC accept (i) the memberships of Durgin and Crowell Lumber Co. (MPEU, End User Sector); Marie’s Way Solar I (AR RG Large Group Seat with Related Persons Fisher Road Solar and Syncarpha Lexington); Phoenix Energy New England (Supplier Sector); Syncarpha Lexington (AR RG Large Group Seat with Related Persons Fisher Road Solar and Marie’s Way Solar I); and Tenaska Power Management (Supplier Sector with Tenaska Power Services); and (ii) the name change of Nautilus Power, LLC (f/k/a/ Essential Power, LLC). Comments on the September Membership filing are due on or before September 21.

• **August 2017 Membership Filing (ER17-2184)**
  On July 31, NEPOOL requested that the FERC accept (i) the memberships of Cianbro Energy (AR Sector Large Renewable Generation Group Seat); Maple Energy (Provisional Member Group Seat); South Jersey Energy ISO3, LLC (Related Person of South Jersey Energy Companies, Supplier Sector); and CWP Energy inc. (Related Person to McGill-St. Laurent, Supplier Sector); and (ii) the termination of the Participant status of Anbaric Management (Provisional Group Member). Comments on the August Membership filing were due on or before August 21; none were filed. This matter is pending before the FERC.

• **July 2017 Membership Filing (ER17-2039)**
  On August 15, the FERC accepted (i) the memberships of MPower Energy (Supplier Sector), Renaissance Power & Gas (Supplier Sector); and Environmental Defense Fund (End User Sector); and (ii) the termination of the Participant status of Brayton Point Energy (Dynegy Related Person (Supplier Sector), who will remain in Pool).

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

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

• **Revised Reliability Standards (Errata): VAR-001-4.1, VAR-002-4 (RD17-7)**
  On August 18, 2017, NERC requested FERC approval of errata changes identified during a periodic review of Reliability Standards VAR-001-4.1 (Voltage and Reactive Control) and VAR-002-4 (Generator Operation for Maintaining Network Schedules). NERC states that the changes will not materially impact those subject to the associated Reliability Standard. NERC requested an effective date that is the first day of the first calendar quarter after the date that the changes are approved. Comments, if any, on the revised Standards are due on or before September 20, 2017.
• **Revised VRFs for Reliability Standard BAL-002-2 (RD17-6)**
  
  On August 14, 2017, NERC requested FERC approve revisions to the Violation Risk Factors (“VRFs”) (from “medium” to “high”) for Requirements R1 and R2 of Reliability Standard BAL-002-2 (Disturbance Control Standard - Contingency Reserve for Recovery from a Balancing Contingency Event). The revisions were directed by the FERC in *Order 835*. Comments, if any, on the revised VRFs are due on or before September 18, 2017.

• **Revised Reliability Standard: CIP-003-7 (RM17-11)**
  
  On March 3, NERC filed for approval changes to Reliability Standard CIP-003 (Cyber Security - Security Management Controls), approval of the associated implementation plan, VRFs, VSLs, and revised NERC Glossary definitions of “Removable Media” and “Transient Cyber Asset”, and the retirement of the currently-effective version of CIP-003 and the NERC Glossary definitions of “Low Impact External Routable Connectivity” and “Low Impact BES Cyber System Electronic Access Point”. The CIP-003 Changes (i) clarify the electronic access control requirements applicable to low impact BES Cyber Systems; (ii) add requirements related to the protection of transient electronic devices used for low impact BES Cyber Systems; and (iii) require Responsible Entities to have a documented cyber security policy related to declaring and responding to CIP Exceptional Circumstances for low impact BES Cyber Systems. The proposed implementation plan provides that the CIP-003-Changes become effective on the first day of the first calendar quarter that is 18 calendar months after the effective date of the FERC’s order approving the CIP-003 Changes. As of the date of this Report, the FERC has not noticed a proposed rulemaking proceeding or otherwise invited public comment.

• **New Reliability Standards: PRC-027-1 and PER-006-1 (RM16-22)**
  
  On September 2, 2016, NERC filed for approval (i) two new Reliability Standards -- PRC-027-1 (Coordination of Protection Systems for Performance During Faults) and PER-006-1 (Specific Training for Personnel), (ii) associated Glossary definitions, (iii) an implementation plan, (iv) VRFs and VSLs, and (v) the retirement of PRC-001-1.1(ii) (together, the “Protection System Changes”). NERC stated that the purpose of the Protection System Changes is to: (1) maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (“BES”) Elements, such that those Protection Systems operate in the intended sequence during Faults; and (2) require registered entities to provide training to their relevant personnel on Protection Systems and Remedial Action Schemes (“RAS”) to help ensure that the BES is reliably operated. NERC requested that the new Standards and definitions become effective on the first day of the first calendar quarter that is 24 months following the effective date of the FERC’s order approving the Standards. As of the date of this Report, the FERC still has not noticed a proposed rulemaking proceeding or otherwise invited public comment.

• **NOPR: Revised Reliability Standard: PRC-012-2 (RM16-20)**
  
  On January 19, 2017, the FERC issued a NOPR proposing to approve Reliability Standard PRC-012-2 (Remedial Action Schemes), its associated implementation plan, VRFs, VSLs, and effective date, and retirement of PRC-015-1 and PRC-016-1 (together, the “RAS Changes”). In addition, the FERC proposes to withdraw pending Standards PRC-012-1, PRC-013-1, and PRC-014-1. The RAS Changes are designed to ensure that remedial action schemes do not introduce unintentional or unacceptable reliability risks to the BES. NERC requested that the RAS Changes become effective on the first day of the first calendar quarter that is 36 months after the effective date of an order approving the Standard, pursuant to the Implementation Plans included with the Changes. Comments on the *RAS Changes NOPR* were due on or before April 10, 2017, and were filed by NERC, NESCOE, ISO-NE/IESO/NYISO, MISO, Bonneville, EEI, and ITC. This matter is pending before the FERC.

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59 The *RAS Changes NOPR* was published in the *Fed. Reg.* on Feb. 8, 2017 (Vol. 82, No. 25) pp. 9,702-9,706.
• NOPR: Revised Reliability Standards: BAL-005-1 & FAC-001-3 (RM16-13)

On September 22, 2016, the FERC issued a NOPR proposing to approve Reliability Standards BAL-005-1 (Balancing Authority Control) and FAC-001-3 (Facility Interconnection Requirements), and associated Glossary definitions, implementation plan, VRFs and VSLs (together, the “Frequency Control Changes”). As previously reported, NERC stated that the Frequency Control Changes clarify and refine Requirements for accurate, consistent, and complete reporting of Area Control Error (“ACE”) calculations. NERC indicated that the Frequency Control Changes will improve reliability by supporting efforts to maintain Interconnection frequency at 60 Hz in a manner consistent with FERC directives, technological developments, and NERC’s current framework of integrated Reliability Standards. NERC requested that the Frequency Control Changes become effective on the first day of the first calendar quarter that is 12 months after the effective date of an order approving the Standard, pursuant to the Implementation Plans included with the Changes. Comments on the Frequency Control Changes NOPR were due on or before November 28, 2016, and were filed by NERC, EEI, Bonneville, Idaho Power and J. Appelbaum.

On March 7, the FERC issued a data request seeking additional information about the current back-up power supply practices of a representative sample of entities potentially affected by the Frequency Control Changes. NERC filed its response to the FERC’s data request on April 6. This matter is pending before the FERC.

• NOPR: Revised Reliability Standard: MOD-001-2 (RM14-7)

The ATC NOPR remains pending before the FERC. As previously reported, the FERC’s June 19, 2014, NOPR proposed to approve changes to MOD-001-2 (Modeling, Data, and Analysis - Available Transmission System Capability) to replace, consolidate and improve upon the Existing MOD Standards in addressing the reliability issues associated with determinations of Available Transfer Capability (“ATC”) and Available Flowgate Capability (“AFC”). MOD-001-2 will replace the six Existing MOD Standards to exclusively focus on the reliability aspects of ATC and AFC determinations. NERC requested that the revised MOD Standard be approved, and the Existing MOD Standards be retired, effective on the first day of the first calendar quarter that is 18 months after the date that the proposed Reliability Standard is approved by the FERC. NERC explained that the implementation period is intended to provide NAESB sufficient time to include in its WEQ Standards, prior to MOD-001-2’s effective date, those elements from the Existing MOD Standards, if any, that relate to commercial or business practices and are not included in proposed MOD-001-2. The FERC sought comment from NAESB and others whether 18 months would provide adequate time for NAESB to develop related business practices associated with ATC calculations or whether additional time may be appropriate to better assure synchronization of the effective dates for the proposed Reliability Standard and related NAESB practices. The FERC also sought further elaboration on specific actions NERC could take to assure synchronization of the effective dates. Comments on this NOPR were due August 25, 2014, and were filed by NERC, Bonneville, Duke, MISO, and NAESB. On December 19, 2014, NAESB supplemented its comments with a report on its efforts to develop WEQ Business Practice Standards that will support and coordinate with the MOD Standards proposed in this proceeding. NAESB issued a report on September 25, 2015, informing the FERC that the NAESB standards development process has been completed and NAESB will file the new suite of business practice standards as part of Version 003.1 of the NAESB WEQ Business Practice Standards in October 2015. As noted above, the ATC NOPR remains pending before the FERC.

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60 Balancing Authority Control, Inadvertent Interchange, and Facility Interconnection Rel. Standards, 156 FERC ¶ 61,210 (Sep. 22, 2016) (“Frequency Control Changes NOPR”).


62 Modeling, Data, and Analysis Rel. Standards, 147 FERC ¶ 61,208 (June 19, 2014) (“ATC NOPR”).

63 The 6 existing MOD Standards to be replaced by MOD-001-2 are: MOD-001-1, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-1a and MOD-030-2.

• **2018 NERC/NPCC Business Plans and Budgets (RR17-7)**
  On August 23, 2017, NERC submitted its proposed Business Plan and Budget, as well as the Business Plans and Budgets for the Regional Entities, including NPCC, for 2018. FERC regulations require NERC to file its proposed annual budget for statutory and non-statutory activities 130 days before the beginning of its fiscal year (January 1), as well as the annual budget of each Regional Entity for their statutory and non-statutory activities, including complete business plans, organization charts, and explanations of the proposed collection of all dues, fees and charges and the proposed expenditure of funds collected. NERC reports that its proposed 2018 Funding requirement represents an overall increase of approximately $2.8 million (4%) over NERC’s 2017 Funding requirement. The NPCC U.S. allocation of NERC’s net funding requirement is $4.1 million. NPCC has requested $15.11 million in statutory funding (a U.S. assessment per kWh (2016 NEL) of $0.0000450) and $1.07 million for non-statutory functions. Comments on this filing are due on or before September 13, 2017. Thus far

• **Rules of Procedure Changes (RR17-6)**
  On June 26, 2017, NERC filed for approval revisions to Sections 600 (Personnel Certification Program) and 900 (Training and Education) of the NERC Rules of Procedure (“ROP”). The purpose of the revisions is to (i) clarify the scope of the Personnel Certification Program, the Training and Education Program and the Continuing Education Program; and (ii) streamline and align the language of the ROP with current practices of those programs. NERC stated that the changes are part of its first comprehensive review to modernize and align the language of the ROP with current NERC practices. NERC requested that the proposed revisions be made effective upon FERC approval. Comments on this filing were due on or before July 17, 2017 and were filed jointly by the Alberta Electric System Operator (“AESO”), The California Independent System Operator (“CAISO”), The Independent Electricity System Operator (“IESO”), ISO-NE and PJM (“System Operators”). System Operators, while agreeing that changes to Sections 600 and 900 are needed, nevertheless disagreed with the proposed changes as written and the rationale for making those changes in the first instance. This matter is pending before the FERC.

• **Annual NERC CMEP Filing (RR15-2)**
  On February 22, NERC submitted a compliance filing reviewing the progress of its risk-based Compliance Monitoring and Enforcement Program (“CMEP”) program. In this filing, NERC identified and proposed two enhancements to the risk-based CMEP: (1) providing minimal risk Compliance Exceptions (“CEs”) identified through self-logging to FERC non-publicly; and (2) expanding the use of CEs to include certain moderate risk noncompliance currently processed through Find, Fix, Track and Report (“FFTs”). Comments on this filing were submitted by the ISO/RTO Council (“IRC”), AEP, EEI, PPL, and jointly by the American Public Power Association (“APPA”), the Electricity Consumers Resource Council (“ELCON”), the National Rural Electric Cooperative Association (“NRECA”), and the Transmission Access Policy Study Group (“TAPS”). This filing is pending before the FERC.

### XI. Misc. - of Regional Interest

• **203 Application: CPV Towantic/Archmore (EC17-158)**
  On August 15, and as corrected on August 21, CPV Towantic, GE Towantic Holdings and Aircraft Services Corp. requested authorization for a transaction by which Archmore International Infrastructure Funds through a wholly-owned indirect subsidiary will acquire an approximately 11% interest in CPV Towantic. Comments on the application were due on or before September 5; none were filed. A doc-less intervention was filed by Eversource. This matter is pending before the FERC.

• **203 Application: GenOn Reorganization (EC17-152)**
  On August 4, GenOn Energy Inc. and its direct and indirect public utility subsidiaries (including NEPOOL Participant GenOn Energy Management) asked the FERC to approve certain conversions of GenOn notes into common equity of, and corporate structure changes that will result in, a “reorganized GenOn”. Reorganized GenOn will emerge as a result of a plan of reorganization to be confirmed by the United States

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Bankruptcy Court for the Southern District of Texas in connection with GenOn’s chapter 11 restructuring (the “Restructuring”). As a result of the Restructuring, Reorganized GenOn will not be a subsidiary of, and GenOn Energy Management will no longer be a Related Person to, NRG. Comments on the application were due on or before August 25. A protest was filed, but withdrawn, by Public Citizen, which sought the identities of the Steering Committee of GenOn Noteholders (already available as part of the public version of the application).

- **203 Application: Dynegy (Dighton/Milford)/Marco DM Holdings (EC17-146)**
  On August 1, Dighton Power, LLC (“Dighton”), Milford Power, LLC (“Milford”), and Marco DM Holdings, L.L.C. (“Marco”) requested FERC authorization for a transaction in which Marco will acquire 100% of the equity interests in Dighton and Milford (each, wholly owned subsidiaries of Dynegy). The transaction implements the FERC’s requirement in EC16-93-001, approving Dynegy Inc.’s acquisition of GDF Suez Energy North America, Inc., that Dynegy divest at least 224 MW in the Southeast New England capacity zone. Comments on the application were due on or before August 22; none were filed. A doc-less intervention was filed by Public Citizen. This matter is pending before the FERC.

- **203 Application: NAPG/Mercuria (EC17-144)**
  On July 31, Noble Americas Gas & Power Corp. (“NAPG”) and Mercuria Energy America, Inc. (“Mercuria”) requested FERC authorization for a transaction in which Mercuria will acquire 100% of the equity interests in NAPG. Comments on the application were due on or before August 21; none were filed. A doc-less intervention was filed by Public Citizen. This matter is pending before the FERC.

- **203 Application: PSNH /FPL Wyman 4 (EC17-132)**
  On August 28, the FERC authorized the sale of Public Service Company of New Hampshire d/b/a Eversource Energy’s (“PSNH” or “Seller”) 3.14% ownership interest in W.F. Wyman Station – Unit 4 (“Wyman 4”) and associated jurisdictional facilities to FPL Energy Wyman IV LLC (the “Transaction”). Among other conditions, the order required notice within 10 days of the consummation of the transaction, which as of date of this Report has not been filed. Subject to that notice, this proceeding will be concluded.

- **203 Application: Green Mountain Power/VT Transco (Highgate) (EC17-86)**
  On May 19, the FERC authorized Green Mountain Power (“GMP”) to sell its undivided ownership share in the Highgate Transmission Facility to and Vermont Transco (“VT Transco”) and VTransco to acquire GMP’s undivided ownership share, as well as certain undivided ownership shares of other joint owners of the Highgate Transmission Facility. Among other conditions, the order required notice within 10 days of the consummation of the transaction, which as of date of this Report has not been filed. Subject to that notice, this proceeding will be concluded.

- **203 Application: Green Mountain Power/ENEL Hydros (EC17-76)**
  On May 9, the FERC authorized GMP’s acquisition of the following small hydroelectric generation facilities (each a QF, collectively 8.39 MW of total generating capacity) from subsidiaries of Enel Green Power North America, Inc.: Hoague-Sprague, Kelley’s Falls, Lower Valley, Glen, Rollinsford, South Berwick, Somersworth, and Woodsville. Among other conditions, the order required notice within 10 days of the consummation of the transaction, which as of date of this Report has not been filed. Subject to that notice, this proceeding will be concluded.

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66 The Steering Committee members are: J.P. Morgan Investment Management Inc., PGIM, Inc., Solus Alternative Asset Management LP, Sound Point Capital Management LP, York Capital Management Global Advisors, LLC and MacKay Shields LLC.


69 *Green Mountain Power Corp.*, 159 FERC ¶ 62,144 (May 9, 2017).
• **203 Application: NSTAR/WMECO Merger (EC17-62)**
  On March 2, 2017, the FERC authorized Eversource’s internal reorganization under which Western Massachusetts Electric Company (“WMECO”) will merge with and into NSTAR Electric Company (“NSTAR”), with NSTAR as the surviving entity. Applicants committed to hold harmless transmission and wholesale customers from transaction-related costs for five years to the extent that such costs exceed savings related to the merger. Among other conditions, the *NSTAR/WMECO Merger Order* required Eversource to notify the FERC within 10 days of the consummation of the merger, which was expected to occur on January 1, 2018.

• **MOPR-Related Proceedings (PJM, NYISO) (EL16-49; EL13-62)**
  In two proceedings which, unless narrowly limited solely to the unique facts of the directly applicable markets (PJM in EL16-49; NYISO in EL13-62), could impact the New England market through FERC jurisdictional or other determinations, NEPOOL filed limited comments requesting that any Commission action or decision be limited narrowly to the facts and circumstances as presented in the applicable market. NEPOOL urged that any changes that may be ordered by the Commission in the proceedings not circumscribe the results of NEPOOL’s stakeholder process or predetermine the outcome of that process through dicta or a ruling concerning different markets with different history and different rules. NEPOOL’s comments were filed on January 24 in the NYISO proceeding; January 30 in the PJM proceeding, and are pending before the FERC. Since the last Report, EPSA filed motions to lodge information in each proceeding. In the PJM proceeding, EPSA moved to lodge a July 14, 2017 Memorandum Opinion and Order of the United States District Court for the Northern District of Illinois, Eastern Division, which dismissed challenges to the zero emissions credits (“ZECs”) legislation enacted by the State of Illinois. In the NYISO proceeding, in a substantively similar motion, EPSA moved to lodge a Memorandum and Order of the New York District Court dismissing challenges to the ZECs program implemented by the NYPSC. In each case, EPSA reiterates its position that unless addressed, the ZEC programs will adversely impact the respective markets. These proceedings remain pending before the FERC.

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

• **LCC Agreement: National Grid (ER17-2339)**
  On August 21, 2017, National Grid filed a Local Control Center (“LCC”) Agreement among New England Power Company (“NEP”) and a number of Participants that sets forth the terms pursuant to which certain local control center services are to be provided at or through NEP’s dispatching center that is operated under the ISO’s direction/authorization. The LCC Agreement supersedes and replaces the Rhode Island, Eastern Massachusetts, Vermont Energy Control (“REMVEC”) II Agreement and the related REMVEC Security Analysis Services Agreement. An August 17, 2017 effective date was requested. Comments on this filing are due on or before September 11, 2017. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

• **LCC Agreement: NSTAR (ER17-2324)**
  On August 18, 2017, NSTAR filed LCC and Telemetering Agreements with Reading Municipal Light Department (“Reading”). The Agreements set forth the terms pursuant to which certain local control center services are to be provided at or through NSTAR’s (rather than NEP’s) dispatching center that is operated under the ISO’s direction/authorization. An August 17, 2017 effective date was requested. Comments on this filing are due on or before September 8, 2017. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

• **IA: CMP/Bucksport (ER17-2198)**
  On July 31, 2017, CMP filed a First Amendment to the Bucksport Generation LLC Interconnection Agreement in order to extend the term of the Agreement until September 28, 2031 (the initial Agreement

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expired on April 17, 2017), with automatic renewals for each successive one-year period thereafter absent termination by a party, and to add termination procedures and termination costs provisions that are consistent with the provisions contained in the ISO Tariff’s Schedule 22 pro forma LGIA. The Amended Agreement will replace the initial Agreement in its entirety. An August 1, 2017 effective date was requested. Comments on this filing were due on or before August 21, 2017; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement: NSTAR/Essential Power Newington (ER17-1915)**
  On August 11, the FERC accepted a Design and Engineering Agreement (“D&E Agreement”) between NSTAR and Essential Power Newington (designated as service agreement IA-NSTAR-34) that sets forth the terms and conditions under which NSTAR will undertake certain design and engineering activities on its transmission system in connection with Essential Power Newington’s FCA11 New Capacity Qualification Determination Notification. The FERC accepted the D&E Agreement effective as of August 26, 2017. Unless the August 11 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Maine Power Express Negotiated Rates Determination Request (ER16-1619)**
  On May 26, Maine Power Express LLC (“MPX”) filed a motion asking the FERC to determine that its July 1, 2016 order, authorizing MPX to sell transmission rights at negotiated rates, permits MPX to sell the Maine Power Express merchant transmission project’s capacity pursuant to the March 30, 2017 Massachusetts RFP. MPX requested expedited treatment of and a shortened comment period for its request, given the July 27 RFP bid deadline (which has since passed). As of the date of this Report, a comment date has not been set. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Emera MPD OATT Changes (ER15-1429; EL16-13, ER12-1650)**
  As previously reported, the FERC conditionally accepted, on December 7, 2015, changes to the Maine Public District (“MPD”) Open Access Transmission Tariff (“MPD OATT”), including to the rates, terms, and conditions set forth in MPD OATT Attachment J. However, the FERC found, ultimately, that the changes to the MPD OATT had not been shown to be just and reasonable, may be unjust and unreasonable, instituted a Section 206 proceeding (in EL16-13) to examine the provisions, and set the matter for a trial-type evidentiary hearing, to be held in abeyance pending the outcome of settlement judge procedures (see below).

**Background (ER15-1429).** Emera Maine, as successor to Maine Public Service Company (“Maine Public”), provides open access to Emera Maine’s transmission facilities in northern Maine (the “MPD Transmission System”) pursuant to the MPD OATT. Emera Maine stated that the changes to the MPD OATT were needed to ensure that, in light of the filing by Emera of consolidated FERC Form 1 data (data comprising both the former Bangor Hydro and Maine Public systems), charges for service under the MPD OATT reflect only the costs of service over the MPD Transmission System. Emera Maine also proposed additional, limited changes to the MPD OATT. A June 1, 2015 effective date was requested. The “Maine

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71 Specifically, NSTAR has agreed to make changes to the Zone 2 timer on both primary (P1) and backup (P2) relays at its Mystic Substation that are associated with NSTAR Line 423-515.

72 Maine Power Express, 156 FERC ¶61,002 (July 1, 2016).

73 The Maine Power Express project is a proposed 315-mile, 1,000 MW HVDC completely underground merchant transmission project that will originate in Haynesville, Maine, and terminate at a new DC/AC converter station in Boston connected with the Eversource transmission system. MPX anticipates that the Project will be operational in 2021.

Customer Group\textsuperscript{75} filed a motion to reject (“Motion to Reject”) the April 1 Filing, asserting the April 1 Filing was deficient because, rather than actual rates, it included proxy rates that MPD said would be replaced with 2014 Form 1 numbers when MPD’s 2014 Form 1 was available. On April 22, the Maine PUC and the Maine Customer Group protested the filing. The MPUC challenged three aspects of the filing: (i) the proposed increase of ROE from 9.75\% to 10.20\% based on anomalous economic conditions; (ii) the change from a measured loss factor calculation to a fixed loss factor; and (iii) the use of end-of-year account balances, rather than average 13-month account balances, for determination of facilities that are included in rate base. In addition to those aspects, the Maine Customer Group further challenged: (iv) inclusion of an out-of-period adjustment to rate base for forecasted transmission; (v) the proposed capital structure, which they assert is artificially distorted to accommodate a requirement resulting from the merger of Emera Maine’s predecessor companies; and (vi) the proposed new cost allocation scheme. On April 24, Emera Maine answered the Maine Customer Group’s Motion to Reject. On April 29, the Maine Customer Group answered Emera Maine’s April 24 answer. On May 1, Emera Maine filed an amendment and errata to its April 1 filing, in part reflecting 2014 FERC Form 1 data rather than estimated data. On May 7, Emera Maine answered the April 22 Maine PUC and MCG protests and the MCG’s April 29 answer. On May 8, MCG moved to compel revision to Emera’s May 1 filing, asserting that it was not filed in accordance with Emera’s OATT, and specifically the Protocols for Implementing and Reviewing Charges Established by the Attachment J Rate Formulas (the “Motion to Compel”). MCG also protested the May 1 filing on May 22. On May 26, Emera Maine answered MCG’s May 8 Motion to Compel, which MCG answered the next day.

On June 2, 2016, the FERC granted Maine Customer Group’s Motion to Compel, and set the remaining issues with respect to Emera Maine’s 2014 and 2015 Annual Updates for hearing and settlement judge procedures.\textsuperscript{76} The FERC also consolidated ER12-1650 with this proceeding. In addition, the FERC directed that Emera Maine to make a compliance filing, on or before July 5, that (1) revises its 2014-2015 formula rate charges to correct the errors the Maine Customer Group raised with respect to amortization of long-term debt costs and post-retirement benefits other than pensions, and (2) imputes the retired debt balance for the tax-free Maine Public bonds ($22.6 million) into the capital structure calculation for the 2014-2015 Rate Year. Emera Maine requested rehearing of the June 2 order on July 5. On January 6, 2017, the FERC denied rehearing and Emera Maine’s alternative request for consolidation with the ongoing proceedings in Docket Nos. EC10-67-002, \textit{et al}.\textsuperscript{77}

\textit{Hearing and Settlement Judge Procedures}. The FERC encouraged the parties to make every effort to settle their disputes before hearing procedures are commenced, and continues to hold hearings in abeyance pending the outcome of settlement judge procedures. As previously reported, Chief Judge Cintron substituted ALJ Dring in place of ALJ Johnson in mid-September as the settlement judge for these proceedings. Settlement conferences before Judge Johnson were held on January 5, March 3, and April 26, 2016 and on October 25 and December 1 before Judge Dring. Since the last Report, Judge Dring issued on May 23 a ninth status report (i) again indicating that the parties have reached a settlement in principal and are memorializing their agreement, and (ii) recommending that settlement judge procedures be continued.

\textit{Settlement Agreement (-006)}. On June 22, Emera Maine submitted an uncontested Joint Offer of Settlement (“Offer of Settlement”) between itself, Houlton Water Company, Van Buren Light and Power District, Eastern Maine Electric Coop., ReEnergy Biomass Operations, the MPUC, and Maine OPA (collectively, the “Settling Intervenors”). If approved, the Offer of Settlement will resolve all issues pending in these proceedings. This settlement does not resolve the matters set for hearing and settlement judge procedures in \textit{Emera Maine and BHE Holdings}, 155 FERC ¶ 61,230 (2016). FERC Staff filed its comments on the Offer of Settlement on July 12, 2017. In its comments, Staff did not oppose the settlement and advised


\textsuperscript{76} \textit{Emera Maine}, 155 FERC ¶ 61,233 (June 2, 2016), \textit{reh’g denied}, 158 FERC ¶ 61,012 (Jan. 6, 2017).

\textsuperscript{77} \textit{Emera Maine}, 158 FERC ¶ 61,012 (Jan. 6, 2017) (“January 6 Order”).
of its belief “the proposed Settlement, in the aggregate, is fair, reasonable, and in the public interest”. Although Staff denied “eight ways in which it believes the formula rate is insufficiently transparent,” Staff stated it “does not oppose certification of the Settlement by the Settlement Judge and subsequent approval by the Commission.” Reply Comments were due July 24, 2017; none were filed. On July 26, Judge Dring certified the Settlement to the Commission. Accordingly, on July 27, Chief Judge Cintron terminated settlement judge procedures, subject to final action by the Commission. The Settlement is now pending before the Commission.

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

- **FERC Enforcement Action: Westar Energy (IN15-8)**
  On August 24, the FERC approved a Stipulation and Consent Agreement⁷⁹ that resolves its investigation into whether Westar Energy, Inc. (“Westar Energy”) violated various provisions of the Southwestern Power Pool (“SPP”) Tariff.⁸⁰ Under the Settlement, in which Westar Energy admitted it had inadvertently violated a number of SPP Tariff provisions, Westar Energy agreed to pay a **$180,000 civil penalty** to the United States Treasury⁸¹ (Westar Energy had already disgorged to SPP the $60,000 in make-whole payments it had received but was not otherwise entitled to). Westar also agreed to be subject to monitoring that includes submission of annual compliance monitoring reports for two years, with the requirement of a third year at OE’s option.⁸² If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **FERC Enforcement Action: ATC (IN17-5)**
  On August 28, the FERC approved a Stipulation and Consent Agreement⁸³ that resolves its investigation into whether American Transmission Company, LLC (“ATC”) violated FPA Sections 203 (by failing to seek pre-approval from the FERC before acquiring 22 jurisdictional facilities) and 205 (by failing to timely file with the FERC jurisdictional agreements prior to commencement and notice following termination, as required).⁸⁴ Under the Settlement, in which ATC admits the violations, ATC agreed to pay a **$205,000 civil penalty**. During the pendency of the investigation, ATC paid roughly **$1.4 million** in time-value refunds to its customers associated with agreements under which service commenced prior to making the required Section 205 filings. ATC also agreed to be subject an annual compliance report.⁸⁵ If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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⁸⁰ As reported in previous Reports, FERC Staff preliminarily determined that Westar Energy included incorrect cost inputs in its mitigated energy offer curves and failed to timely update other cost inputs, as required by the SPP Tariff. As explained in the *Westar Order*, a Westar employee inadvertently increased variable operating and maintenance fuel charges, and Westar input inaccurate heat rate coefficients, resulting in incorrect mitigated energy offer curves and make-whole payments of approximately $60,000 that it otherwise would not have earned. Westar also failed to update other fuel costs for other units which did not result in make-whole payments.
⁸¹ *Id.* at P 2.
⁸² *Id.*
⁸⁴ OE determined that ATC violated (i) FPA Section 203(a)(1)(B) by merging or consolidating facilities subject to the FERC’s jurisdiction without obtaining prior FERC authorization in 21 transactions undertaken between Aug. 8, 2006 and Feb. 13, 2014 and valued from $1,513 to $1.2 million and (ii) FPA Section 205 by commencing jurisdictional service under 42 agreements and terminating 6 jurisdictional contracts without providing the requisite notice between October 17, 2000 and May 26, 2011.
⁸⁵ *Id.*
• **FERC Enforcement Action: City Power Marketing and Tsingas (IN15-5)**

On August 22, the FERC approved a Stipulation and Consent Agreement\(^{86}\) that resolves its investigation into (and subsequent litigation in the US District Court for the District of Columbia\(^{87}\) regarding) whether City Power Marketing, LLC (“City Power”) and K. Stephen Tsingas (“Tsingas”, and together with City Power, the “City Power Respondents”) violated the FERC’s Anti-Manipulation Rules by engaging in fraudulent Up To Congestion (“UTC”) transactions in PJM’s energy markets.\(^{88}\) Under the Settlement, in which City Power Respondents neither admit nor deny the alleged violations, City Power agreed to pay a $9 million civil penalty to the United States Treasury and Tsingas agreed to pay a total of $2.72 million (a $1.3 million disgorgement to PJM and a civil penalty of $1.42 million) as well as to a 3-year prohibition (whether directly or indirectly through consulting, advising, directing, or strategizing) on any trades (physical or financial or virtual) within the FERC’s jurisdiction. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pgerity@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 Enforcement 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.

Unlike a staff NOV, a FERC order converting an informal, non-public investigation to a formal, non-public investigation does not indicate that the FERC has determined that any entity has engaged in market manipulation or otherwise violated any FERC order, rule, or regulation. It does, however, give OE’s Director, and employees designated by the Director, the authority to administer oaths and affirmations, subpoena witnesses, compel their attendance and testimony, take evidence, compel the filing of special reports and responses to interrogatories, gather information, and require the production of any books, papers, correspondence, memoranda, contracts, agreements, or other records.

• **FERC Audit of ISO-NE (PA16-6)**

The FERC’s audit of ISO-NE docketed in this proceeding is on-going. As previously reported, the FERC informed ISO-NE on November 24, 2015 that it would evaluate ISO-NE’s compliance with: (1) the transmission provider obligations described in the Tariff, (2) Order 1000 as it relates to transmission planning and expansion, and interregional coordination, (3) accounting requirements of the Uniform System of Accounts under 18 C.F.R. Part 101, (4) financial reporting requirements under 18 C.F.R. Part 141; and (5) record retention requirements under 18 CFR Part 125. The FERC indicated that the audit will cover the July 10, 2013 period through the present.

**XII. Misc. - Administrative & Rulemaking Proceedings**

• **State Policies & Wholesale Markets Operated by ISO-NE, NYISO, PJM (AD17-11)**

As previously reported, the FERC held a 2-day technical conference (on May 1-2) to foster further discussion regarding the development of regional solutions in the Eastern RTOs/ISOS that reconcile the

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\(^{86}\) *Maxim Power Corp. et al., 156 FERC ¶ 61,223 (Sep. 26, 2016).*

\(^{87}\) *FERC v. Maxim Power Corp. et al., No. 3:15-cv-30113-MGM (D. Mass.).*

\(^{88}\) As previously reported, the FERC found that City Power Respondents violated its Anti-Manipulation Rules by engaging in fraudulent UTC transactions in PJM’s energy markets. *City Power Mkt’g, LLC and K. Stephen Tsingas, 152 FERC ¶ 61,012 (July 2, 2015) (“City Power Penalties Order”).* The City Power Penalties Order required City Power Respondents to jointly and severally disgorge unjust profits of $1,278,358 and to together pay $15 million in civil penalties (City Power - $14 million; Tsingas - $1 million). At City Power Respondent’s election, the City Power Penalties Order proceeded to, and was in the midst of, a *de novo* review before the federal district court in the District of Columbia. The Settlement reduces the civil penalty amount to be paid by City Power by $5 million.
competitive market framework with the increasing interest by states to support particular resources or resource attributes. FERC staff sought to “discuss long-term expectations regarding the relative roles of wholesale markets and state policies in the Eastern RTOs/ISOs in shaping the quantity and composition of resources needed to cost-effectively meet future reliability and operational needs”. A more detailed summary of the technical conference was circulated with the last Report. Pre-conference comments from the conference’s speakers, panelists and other interested parties are available in the FERC’s eLibrary and through the tech conference’s calendar entry. Those interested were invited to submit post-conference comments on or before June 22. Comments were received from over 80 parties, and were briefly summarized at the Summer Meeting. Reply comments, not exceeding 10 pages, were due, following a one-week extension granted by the FERC, on July 14, and were filed by over 30 parties. This matter is pending before the FERC.

- **BPS Reliability Technical Conference (AD17-8)**
  On June 22, the FERC held a technical conference that discussed policy issues related to the reliability of the Bulk-Power System (“BPS”). Panel presentations covered the following topics: (i) an overview on the state of reliability; (ii) international perspectives; (iii) the potential for long-term and large-scale disruptions to the BPS; and (iv) grid security. Written comments were filed ahead of the conference by the Chairman of the Ohio Public Utilities Commission and by a representative of the Large Public Power Council. Speaker materials, as well as a transcript of the technical conference, are posted on the FERC’s eLibrary. Since the last report, on June 20, Environmental Defense Fund filed post-technical conference comments. This matter is pending before the FERC.

- **Electric Storage Resource Utilization in RTO/ISO Markets (AD16-25)**
  As previously reported, the FERC held a technical conference on November 9, 2016 to discuss the utilization of electric storage resources as transmission assets compensated through RTO/ISO transmission rates, for grid support services that are compensated in other ways, and for multiple services. On November 14, the FERC invited all those interested to file, on or before December 14, 2016, post-technical conference comments on the topics discussed in the November 1 Supplemental Notice of Technical Conference. Comments were filed by over 45 parties, including Avangrid, Brookfield, EEI, Energy Storage Association, Exelon, FirstLight, NEPGA, NextEra, PSEG, Solar City/Tesla, and UCS. This matter is pending before the FERC.

- **Competitive Transmission Development Rates (AD16-18)**
  The FERC held a technical conference on a June 27-28, 2016 to discuss competitive transmission development process-related issues, including use of cost containment provisions, the relationship of competitive transmission development to transmission incentives, and other ratemaking issues. In addition, participants had the opportunity to discuss issues relating to interregional transmission coordination, regional transmission planning and other transmission development issues. Pre-technical conference comments were filed by over 20 parties, including by NESCOE, BHE US Transmission, LSPower, and NextEra Energy Transmission. Technical conference materials are available on the FERC’s e-Library. Post-technical conference comments were filed by over 60 parties, including: NEPOOL, ISO-NE, Avangrid, AWEA, BHE US Transmission, EDF Renewables, EEI, ELCON, Eversource, Exelon, LSP Transmission Holdings, MMWEC, National Grid, NESCOE, NextEra, and PSEG.

- **Reactive Supply Compensation in RTO/ISO Markets (AD16-17)**
  A workshop to discuss compensation for Reactive Supply and Voltage Control (Reactive Supply) in RTO/ISO markets was held on June 30, 2016. The workshop explored the types of costs incurred by generators for providing Reactive Supply capability and service; whether those costs are being recovered solely as compensation for Reactive Supply or whether recovery is also through compensation for other services; and different methods by which generators receive compensation for Reactive Supply (e.g., FERC-approved revenue requirements, market-wide rates, etc.). The workshop also explored potential adjustments in compensation based on changes in Reactive Supply capability and potential mechanisms to prevent overcompensation for Reactive Supply. Technical conference materials are available on the FERC’s e-Library. Written comments were filed by, among others, NYISO, PJM, the PJM IMM, AWEA, EEI, EPSA,
EDF Renewables, Talen, Essential Power, and Exelon. EDF Renewables filed reply comments on August 19; the PJM IMM on August 21. This matter remains pending before the FERC.

- **PURPA Implementation (AD16-16)**

  A workshop to discuss issues associated with the FERC’s implementation of PURPA was held on June 29, 2016. The conference focused on two issues: the mandatory purchase obligation under PURPA and the determination of avoided costs for those purchases. Panelists’ advanced written comments and materials from the technical conference are available on the FERC’s e-Library. Post-technical conference comments addressing (1) the use of the “one-mile rule” to determine the size of an entity seeking certification as a small power production qualifying facility (“QF”); and (2) minimum standards for PURPA-purchase contracts were filed by over 40 parties, including AWEA, Covanta, CT PURA/MA AG, Duke, EDP, EEI, ELCON, NARUC, and NRECA.

- **Price Formation in RTO/ISO Energy and Ancillary Services Markets (AD14-14)**

  As previously reported, the FERC directed each RTO/ISO to publicly provide, and the RTO/ISO’s provided, information related to five price formation issues: (1) pricing of fast-start resources; (2) commitments to manage multiple contingencies; (3) look-ahead modeling; (4) uplift allocation; and (5) transparency. The FERC indicated it would use the reports and comments filed in response thereto to determine what further action is appropriate. NOPRs addressing fast-start pricing (RM17-3) and uplift allocation and transparency (RM17-2) have already been issued.

- **NOI: FERC’s Policy for Recovery of Income Tax Costs & ROE Policies (PL17-1)**

  On December 15, 2016, the FERC issued a notice of inquiry (“NOI”) seeking comments regarding how to address any double recovery resulting from the FERC’s current income tax allowance and ROE policies. The NOI followed the D.C. Circuit’s *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”. Comments and reply comments were submitted by over 25 and 18 parties, respectively. This matter is pending before the FERC.

- **NOPR: LGIA/LGIP Reforms (RM17-8)**

  As previously reported, the FERC issued a NOPR on December 15, 2016 proposing reforms designed to improve certainty, promote more informed interconnection, and enhance interconnection

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91 *United Airlines Inc., et al. v. FERC*, 827 F.3d 122, 134, 136 (D.C. Cir. 2016) (“*United Airlines*”).

92 Id. at 137.


94 To accomplish this goal, the FERC proposes to: (1) revise the *pro forma* LGIP to require transmission providers that conduct cluster studies to move toward a scheduled, periodic restudy process; (2) remove from the *pro forma* LGIA the limitation that interconnection customers may only exercise the option to build transmission provider’s interconnection facilities and standalone network upgrades if the transmission owner cannot meet the dates proposed by the interconnection customer; (3) modify the *pro forma* LGIA to require mutual agreement between the transmission owner and interconnection customer for the transmission owner to opt to initially self-fund the costs of the construction of network upgrades; and (4) require that the RTO/ISO establish dispute resolution procedures for interconnection disputes. The Commission also seeks comment on the extent to which a cap on the network upgrade costs for which
Based, in part, on input received in response to AWEA’s petition for changes to the pro forma LGIP/LGIA, and the FERC’s May 13, 2016 technical conference to explore generator interconnection issues (as reported previously under Docket Nos. RM16-12; RM15-21), the FERC identified proposed reforms which it states could remedy potential shortcomings in the existing interconnection processes. The FERC also sought comment on whether any of its proposed reforms should be applied to the pro forma SGIP/SGIA. 60 sets of comments on and answer to the LGIP/LGIA Reforms NOPR were submitted, including comments by: NEPOOL (approved at the April 7 Participants Committee meeting), ISO-NE, Avangrid, EDF Renewable, EDP Renewables, Eversource, Exelon, Inenergy, National Grid, NextEra, APPA/LPPC/NRECA, AWEA, EEI, ELCON, ESA, and Public Interest Organizations. This matter is pending before the FERC.

- **NOPR: Fast-Start Pricing in RTO/ISO Markets (RM17-3)**

On December 15, the FERC issued a NOPR proposing to require each RTO and ISO to incorporate market rules that meet certain requirements when pricing fast-start resources. The FERC stated that the reforms should lead to prices that more transparently reflect the marginal cost of serving load, which would reduce uplift costs and thereby improve price signals to support efficient investments. Specifically, the FERC proposes to require that each RTO/ISO incorporate the following five requirements for its fast-start pricing:

1. an RTO/ISO must apply fast-start pricing to any resource committed by the RTO/ISO that is able to start up within 10 minutes or less, has a minimum run time of one hour or less, and that submits economic energy offers to the market;
2. when an RTO/ISO makes a decision to commit a fast-start resource, it should incorporate commitment costs, i.e., start-up and no-load costs, of fast-start resources in energy and operating reserve prices, but must do so only during the fast-start resource’s minimum run time;
3. an RTO/ISO must modify its fast-start pricing to relax the economic minimum operating limit of fast-start resources and treat them as dispatchable from zero to the economic maximum operating limit for the purpose of calculating prices;

**Id.** at P 6.

The FERC proposes to: (1) require transmission providers to outline and make public a method for determining contingent facilities in their LGIPs and LGIAs based upon guiding principles in the Proposed Rule; (2) require transmission providers to list in their LGIPs and on their OASIS sites the specific study processes and assumptions for forming the networking models used for interconnection studies; (3) require congestion and curtailment information to be posted in one location on each transmission provider’s OASIS site; (4) revise the definition of “Generating Facility” in the pro forma LGIP and LGIA to explicitly include electric storage resources; and (5) create a system of reporting requirements for aggregate interconnection study performance. The FERC also seeks comment on proposals or additional steps that the Commission could take to improve the resolution of issues that arise when affected systems are impacted by a proposed interconnection. **Id.** at P 7.

The FERC proposes to: (1) allow interconnection customers to limit their requested level of interconnection service below their generating facility capacity; (2) require transmission providers to allow for provisional agreements so that interconnection customers can operate on a limited basis prior to completion of the full interconnection process; (3) require transmission providers to create a process for interconnection customers to utilize surplus interconnection service at existing interconnection points; (4) require transmission providers to set forth a separate procedure to allow transmission providers to assess and, if necessary, study an interconnection customer’s technology changes (e.g., incorporation of a newer turbine model) without a change to the interconnection customer’s queue position; and (5) require transmission providers to evaluate their methods for modeling electric storage resources for interconnection studies and report to the Commission why and how their existing practices are or are not sufficient. **Id.** at P 8.

**Id.** at P 11.

4. if an RTO/ISO allows offline fast-start resources to set prices for addressing certain system needs, the resource must be feasible and economic; and

5. an RTO/ISO must incorporate fast-start pricing in both the Day-Ahead and Real-Time markets.

Comments on the Fast-Start Pricing NOPR were filed by numerous parties, including NEPOOL, ISO-NE and EEI. Reply comments were filed by MISO and the PJM IMM. Since the last Report, on August 18, the CAISO filed supplemental comments (providing additional information identifying challenges facing CAISO and the adverse impacts it believes the NOPR rules would have on its markets). The Fast-Start Pricing NOPR is pending before the FERC.

  On January 19, 2017, the FERC issued a NOPR proposing to require each RTO and ISO that currently allocates the costs of Real-Time uplift due to deviations to do so only to those market participants whose transactions are reasonably expected to have caused the real-time uplift costs. In addition, the FERC proposed to revise its regulations to enhance transparency by requiring that each RTO/ISO post uplift costs paid (dollars) and operator-initiated commitments (MWs) on its website; and define in its tariff its transmission constraint penalty factors, as well as the circumstances under which those penalty factors can set LMPs, and any procedure for changing those factors. Comments and reply comments on the Uplift/Transparency NOPR were filed by over 40 parties, including: ISO-NE, Brookfield, Calpine, DC Energy, Direct, Exelon, Potomac Economics, Saracen, EEI, APPA/NRECA, Appian Way Energy Partners, AWEA, ELCON, EPSA, Financial Marketers Coalition, and the IRC. This matter is pending before the FERC.

- **NOPR: Electric Storage Participation in RTO/ISO Markets (RM16-23; AD16-20)**
  On November 23, 2016, the FERC issued a NOPR proposing to require each RTO and ISO to revise its tariff “to (1) establish a participation model consisting of market rules that, recognizing the physical and operational characteristics of electric storage resources, accommodates their participation in the organized wholesale electric markets and (2) define distributed energy resource aggregators as a type of market participant that can participate in the organized wholesale electric markets under the participation model that best accommodates the physical and operational characteristics of its distributed energy resource aggregation.” Comments on the Storage NOPR were filed by over 100 parties, including: NEPOOL, ISO-NE, APPA/ NRECA, Avangrid, AWEA, Brookfield, CT DEEP, CT PURA, Dominion, DTE, EEI, ELCON, EPSA, EPRI, ESA, Exelon, FirstLight, Genbright, IPKeys, MA DPU, MIT, MMWEC, NARUC, NERC, NESCOE, NextEra, NRG, SEIA, UCS. Since the last Report, comments were filed by the Harvard Environmental Policy Initiative. This matter is pending before the FERC.

- **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. 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\(^2\) and were filed by over 30 parties, including: APPA, Avangrid, Brookfield, EPSA, Macquarie/DC Energy/Emera Energy Services, NextEra, and NRG.

  The FERC issued Order 833\(^3\) on November 16, 2016. Order 833 amended FERC regulations to implement provisions of the Fixing America’s Surface Transportation ("FAST") Act that pertain to the designation, protection and sharing of Critical Electric Infrastructure Information ("CEII") and amend other regulations that pertain to CEII. The amended procedures will be referred to as the Critical Energy/Electric Infrastructure Information (CEII) procedures. Order 833 became effective February 21, 2017. On December 19, 2016, EEI requested rehearing of Order 833. The FERC issued a tolling order on January 17, affording it additional time to consider the EEI request for rehearing, which remains pending.

- **NOPR: Primary Frequency Response - Essential Reliability Services and the Evolving Bulk-Power System (RM16-6)**
  On November 17, 2016, the FERC issued a NOPR proposing to require all newly interconnecting large and small generating facilities, both synchronous and non-synchronous, to install and enable primary frequency response capability as a condition of interconnection.\(^4\) To implement these requirements, the Commission proposes to revise the pro forma LGIA and the pro forma SGIA. The Primary Frequency Response NOPR follows the FERC’s Frequency Response NOI\(^5\) from early 2016. Comments on the Primary Frequency Response NOPR were filed by over 30 parties, including AWEA, EEI, ELCON, EPSA, ESA, First Solar, the IRC, NRECA, and UCS. Supplemental comments were filed by ELCON. On August 18, 2017, the FERC issued a request for supplemental comments related to whether and when electric storage resources should be required to provide primary frequency response, and the costs associated with primary frequency response capabilities for small generating facilities. Supplemental comments are currently due on or before September 14, 2017. On August 30, APPA, EEI and NRECA ("Joint Associations") requested an extension of the period for filing supplemental comments to October 9, 2017. On September, the FERC granted Joint Associations’ motion and extended the deadline for filing comments to October 10, 2017.

- **Order 831: Price Caps in RTO/ISO Markets (RM16-5)**
  On November 17, 2016, the FERC issued Order 831\(^6\) requiring each RTO/ISO: (i) to cap each resource’s incremental energy offer at the higher of $1,000/MWh or that resource’s verified cost-based

\(^{102}\) The Data Collection NOPR was published in the Fed. Reg. on Aug. 4, 2016 (Vol. 81, No. 150 pp. 51,726-51,772.

\(^{103}\) Regulations Implementing FAST Act Section 61003 – Critical Electric Infrastructure Security and Amending Critical Energy Infrastructure Information; Availability of Certain North American Electric Reliability Corporation Databases to the Commission, Order No. 833, 157 FERC ¶ 61,123 (Nov. 17, 2016) (“Order 833”).

\(^{104}\) Order 833 was published in the Fed. Reg. on Dec. 21, 2016 (Vol. 81, No. 245) pp. 93,732-93,753.


\(^{108}\) Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators, Order No. 831, 157 FERC ¶ 61,115 (Nov. 17, 2016) (“Order 831”), reh’g requested.
incremental energy offer; and (ii) cap verified cost-based incremental energy offers at $2,000/MWh when calculating locational marginal prices (“LMP”). In addition, the FERC clarified that the verification process for cost-based incremental offers above $1,000/MWh should ensure that a resource’s cost-based incremental energy offer reasonably reflects that resource’s actual or expected costs. Order 831 modified the FERC’s Offer Cap NOPR by including a $2,000/MWh hard cap for the purposes of calculating LMPs. Order 831 became effective February 21, 2017.\textsuperscript{109} Market Rule changes implementing Order 831 are required to be filed within 75 days of that effective date, or by May 8, 2017.\textsuperscript{110} (Support for ISO-NE’s proposed compliance changes is on the May 5 Consent Agenda, Item #1.) On December 19, 2017, American Municipal Power Inc. (“AMP”) and APPA, Exelon, NYISO, and TAPS requested rehearing and/or clarification of Order 831. The FERC issued a tolling order on January 17, affording it additional time to consider the requests for rehearing, which remain pending. On January 4, the PJM Market Monitor opposed Exelon’s motion for clarification and/or rehearing. On January 13, MISO submitted comments supporting NYISO request for rehearing. New England’s Tariff revisions in response to requirements of Order 831, requesting an October 1, 2019 effective date, were filed on May 8 and remain pending before the FERC (see ER17-1565, Section III above).

### 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).

- **Technical Conference: Natural Gas Index Liquidity, Price Discovery & Price Formation (AD17-12)**
  The FERC held a technical conference on June 29 on developments in natural gas index liquidity and transparency. The purpose of the technical conference was to understand the state of liquidity in the physical natural gas markets, to explore current trends in physical natural gas trading and price reporting and how the use of natural gas indices have evolved over time, to obtain industry’s views on the current level of confidence in natural gas indices and price formation, and finally, to consider whether there is a need to improve natural gas market liquidity and price reporting and, if so, how. Post-technical conference comments were filed on July 31 by AGA, INGAA, the PJM IMM, Rice Energy Marketing, and Tenaska Marketing Ventures. A transcript of the technical conference is available on the FERC’s eLibrary. This matter is pending before the FERC.

- **Algonquin EDC Capacity Release Bidding Requirements Exemption Request (RP16-618)**
  On March 31, 2016, the FERC conditionally accepted Algonquin tariff modifications and request for waiver that provided an exemption from capacity release bidding requirements for certain types of firm transportation capacity releases by Electric Distribution Companies (“EDCs”) that are participating in state-regulated electric reliability programs.\textsuperscript{111} As previously reported, Algonquin stated that the modifications were consistent with the FERC’s current policy of exempting releases pursuant to state-regulated retail access programs of natural gas local distribution companies (“LDCs”) from bidding requirements. Algonquin added that its proposal (i) supports the efforts of EDCs to increase the reliability of supply for natural gas-fired electric generation facilities in New England and to address high electricity prices during peak periods in New England and therefore is in the public interest; and (ii) furthers the FERC’s initiatives related to gas-electric coordination. On May 9, 2016, the FERC held a technical conference to examine “concerns raised regarding the basis and need for the waiver.” Initial comments were due May 31. Almost two dozen sets of initial comments were filed, raising numerous issues both in support and in opposition to the Algonquin proposal. Reply comments were due June 10, 2016 and were filed by Algonquin Gas Transmission, Sequent Energy Management, L.P. and Tenaska

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\textsuperscript{109} Order 831 was published in the Fed. Reg. on Dec. 5, 2016 (Vol. 81, No. 233) pp. 87,770-87,800.

\textsuperscript{110} The 75-day period ends on Saturday, May 6. Pursuant to Rule 2007 of the FERC’s Rules of Practice & Procedure, if the last day of a time period falls on a weekend, the time period does not end until the close of the next day on which the FERC remains open. See 18 CFR 385.2007(a)(2).

\textsuperscript{111} Algonquin Gas Transmission, LLC, 154 FERC ¶ 61,269 (Mar. 31, 2016).
Marketing Ventures, Indicated Shippers, National Grid, Eversource, Repsol, Calpine, Exelon/NextEra, New England LDCs, CT PURA and the MA AG.

On August 31, 2016, the FERC issued an order in which it rejected Algonquin’s request for a waiver that would have exempted gas-fired generators from capacity release bidding requirements but accepted Algonquin’s proposal to exempt from bidding an EDC’s capacity release to an asset manager who is required to use the released capacity to carry out the EDC’s obligations under the state-regulated electric reliability program.\textsuperscript{112} The FERC explained that its capacity release regulations seek to balance the interests of the releasing shipper in releasing capacity to a replacement shipper of its choosing while still ensuring that allocative efficiency is enhanced by ensuring the capacity is used for its highest valued use.\textsuperscript{113} Algonquin’s proposal, whereby any gas-fired generator to whom EDCs release capacity would be a pre-arranged replacement shipper, failed to meet the standard of “improving the competitive structure of the natural gas industry” as formulated by the FERC in granting bidding exemptions for state-regulated retail access programs.\textsuperscript{114} Furthermore, the FERC found that exemption proponents had not shown why such a broad exemption was necessary in order for EDCs to have a sufficient ability to direct their capacity releases to natural gas-fired generators in order to accomplish the goal of increasing electric reliability.\textsuperscript{115} On September 30, 2016, ConEd and Orange & Rockland Utilities, Inc. (“O&R”) requested clarification of the \textit{Algonquin Order Following Technical Conference}, asking the FERC to clarify certain aspects of its approval exempting from bidding an EDC’s capacity release to an asset manager. Algonquin Gas Transmission, National Grid Electric Distribution Companies, and Sequent Energy Management and Tenaska Marketing Ventures filed answers to the requests for clarification on October 17. Those requests are pending before the FERC.

On September 23, 2016, Algonquin submitted a compliance filing in response to the requirements of the \textit{Algonquin Order Following Technical Conference}. Comments on that compliance were due on or before October 5, 2016; none were filed. The compliance filing remains pending before the FERC.

- **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:

  \textbf{BP (IN13-15).} On July 11, 2016, the FERC issued \textit{Opinion 549}\textsuperscript{116} 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 (“\textit{Anti-Manipulation Rule}”) and section 4A of the Natural Gas Act (“\textit{NGA}”).\textsuperscript{117} 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.”\textsuperscript{118} Accordingly, the FERC assessed a $20.16 million \textit{civil penalty} and required BP to \textit{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

\[\begin{align*}
\textsuperscript{112} & \text{Algonquin Gas Transmission, LLC, 156 FERC ¶ 61,151 (Aug. 31, 2016) (“Algonquin Order Following Technical Conference”).} \\
\textsuperscript{113} & \text{Id. at P 27.} \\
\textsuperscript{114} & \text{Id. at P 34.} \\
\textsuperscript{115} & \text{Id. at P 35} \\
\textsuperscript{116} & \text{BP America Inc., et al., Opinion No. 549, 156 FERC ¶ 61,031 (July 11, 2016) (“BP Penalties Order”).} \\
\textsuperscript{117} & \text{BP America Inc., et al., 152 FERC ¶ 63,016 (Aug. 13, 2015) (“BP Initial Decision”).} \\
\textsuperscript{118} & \text{BP Penalties Order at P 3.} \\
\end{align*}\]
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. BP was directed to pay the civil penalty and disgorgement amount within 60 days of the BP Penalties Order. On August 10, 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, 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, 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.

Total Gas & Power North America, Inc. et al. (IN12-17). On April 28, 2016, the FERC issued a show cause order 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.

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.

119 BP America Inc. et al., 147 FERC ¶ 61,130 (May 15, 2014) (“BP Hearing Order”), reh’g denied, 156 FERC ¶ 61,031 (July 11, 2016).
120 BP America Inc. et al., 156 FERC ¶ 61,174 (Sep. 12, 2016) (“Order Staying BP Disgorgement”)
121 Total Gas & Power North America, Inc., et al., 155 FERC ¶ 61,105 (Apr. 28, 2016) (“TGPNA Show Cause Order”)
122 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.
Staff Notices of Alleged Violations (IN__-___)

Rover. On July 13, 2017, the FERC issued a notice that Staff has preliminarily determined that, between February 2015 and September 2016, Rover Pipeline, LLC and Energy Transfer Partners, L.P. (collectively, “Rover”) violated Section 7 of the Natural Gas Act by failing to fully and forthrightly disclose all relevant information to the FERC in Rover’s application for a Certificate of Public Convenience and Necessity and attendant filings in Docket No. CP15-93. Staff alleges that Rover falsely promised it would avoid adverse effects to a historic resource that it was simultaneously working to purchase and destroy, and subsequently made several misstatements in its docketed responses to FERC questions about why it had purchased and demolished the resource.

National Energy & Trade, L.P. The FERC issued a second notice on August 3 that Staff has preliminarily determined that National Energy & Trade, L.P (“National Energy”) violated the FERC’s Prohibition of Natural Gas Market Manipulation by fraudulently trading physical basis at (i) Texas Eastern M3 (Tetco M3) during the January 2012 bidweek to increase the value of its financial basis position (by selling physical basis at Tetco M3 at arbitrarily low prices early in the morning to benefit a large short financial basis position acquired before bidweek, a large part of which it repurchased after making its physical basis sales) and (ii) at Henry Hub during the April 2014 bidweek to increase the value of its financial exposure (by trading physical basis after the close of the NYMEX solely to benefit National Energy’s exposure to the Henry Hub Inside FERC index).

Recall that Notices of Alleged Violations (“NoVs”) are issued only after the subject of an enforcement investigation has either responded, or had the opportunity to respond, to a preliminary findings letter detailing Staff’s conclusions regarding the subject’s conduct. NoVs are designed to increase the transparency of Staff’s nonpublic investigations conducted under Part 1b of its regulations. A NoV does not confer a right on third parties to intervene in the investigation or any other right with respect to the investigation.

New England Pipeline Proceedings
The following New England pipeline projects are currently under construction or before the FERC:

• Atlantic Bridge Project (CP16-9)
  ▪ Algonquin Gas Transmission filed for Section 7(b) and 7(c) certificate on Oct. 22, 2015.
  ▪ 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.
  ▪ Authorization to proceed with construction of certain Projects segments granted on Mar. 27 and Apr. 13, 2017.
  ▪ Construction began May 1, 2017. Detailed information regarding construction activities will be provided in the weekly construction reports filed in this docket.

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123 See Enforcement of Statutes, Regulations, and Orders, 129 FERC ¶ 61,247 (Dec. 17, 2009), order on requests for reh’g and clarification, 134 FERC ¶ 61,054 (Jan. 24, 2011).

• **Connecticut Expansion Project (CP14-529)**
  - Tennessee Gas Pipeline filed for Section 7(c) certificate July 31, 2014.
  - 72,100 Dth/d of firm capacity.
  - 13.26 miles of three looping segments & facility upgrades/modifications in NY, MA & CT.
  - Certificate of public convenience and necessity granted Mar. 11, 2016.\(^{125}\)
  - Construction began 4th Quarter 2016.
  - In-service: Nov. 2017 (anticipated).

• **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.
  - On April 22, 2016, New York State Department of Environmental Conservation denied Constitution’s application for a Section 401 permit under the Clean Water Act. The decision effectively guarantees that the Constitution Pipeline project will, at best, be delayed by several years.
  - 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.
  - Construction was expected to begin Spring 2016 (after final Federal Authorizations), but has been plagued by delays.
    - On October 13, 2016, the FERC approved Constitution’s request to proceed to remove the felled trees in Pennsylvania, which removal is currently on-going.

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; pgerity@daypitney.com).

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\(^{125}\) *Tennessee Gas Pipeline Co., LLC*, 154 FERC ¶ 61,191 (Mar. 11, 2016) (order issuing certificate); *reh’g requested. See also* 154 FERC ¶ 61,263 (Mar. 30, 2016) (order denying stay); 155 FERC ¶ 61,087 (Apr. 22, 2016) (order denying stay).
• Demand Curve Changes (17-1110**)
  Underlying FERC Proceedings: ER14-1639
  Petitioners: NextEra, NRG, PSEG
  On April 3, 2017, NextEra, NRG and PSEG (“Petitioners”) again petitioned the DC Circuit Court of Appeals for review of the FERC’s Demand Curve orders, which, as previously reported, had been remanded back to the FERC at the FERC’s request following the first appeal by Petitioners. Petitioners’ statement of issues and other initial procedural submissions, as well as the FERC’s initial submissions, were filed May 8. The Clerk granted on June 2 the interventions filed by NEPOOL, NESCOE, CT PURA, and CPV, and ordered the parties by July 7 to submit proposed briefing schedule and formats. The parties submitted their proposal on July 7 and on July 10, the Clerk ordered that the following schedule would apply: Petitioners’ Brief to be filed September 8; Respondent’s Brief, November 7, 2017; Respondent-Intervenors’ Brief(s), November 28, 2017; Petitioners’ Reply Brief, December 28, 2017; Joint Deferred Appendix, January 11, 2018; and Final Briefs, January 18, 2018.

• FCA10 Results (16-1408) and FCA9 Results (16-1068)
  Underlying FERC Proceedings: ER16-1041, ER15-1137
  Petitioners: UWUA Local 464 and Robert Clark
  UWUA Local 464 and Robert Clark (“Petitioners”) filed petitions for review of the FERC’s orders on the FCA10 and FCA9 Results Filings, consolidated by the Court on January 31, 2017. With Final Briefs submitted on June 26, 2017, all briefing is complete and this matter is before the Court.

• NEPGA PER Complaint and FCM Jump Ball and Compliance Proceedings (16-1023/1024)
  Underlying FERC Proceeding: ER14-1050; EL14-52; EL15-25
  Petitioner: NEPGA
  As previously reported, NEPGA filed, on January 19, 2016, a petition for review of the FERC’s orders on NEPGA’s first PER Complaint. On February 24, 2016, the Court granted NEPGA’s motion to consolidate this proceeding with 16-1024. Briefing was completed on November 28, 2016. and this matter remains pending before the DC Circuit. Oral argument has been scheduled for October 27, 2017 at 9:30 a.m. The composition of the argument panel will usually be revealed 30 days prior to the date of oral argument.

• Base ROE Complaints II & III (2012 & 2014) (15-1212)
  Underlying FERC Proceedings: EL13-33; EL14-86
  Appellants: New England Transmission Owners
  As previously reported, the TOs filed a petition for review of the FERC’s orders in the 2012 and 2014 ROE complaint proceedings on July 13, 2015. On August 14, 2015, the TOs filed an unopposed motion to hold this case in abeyance pending final FERC action on the 2012 and 2014 ROE Complaints (see Section I above). On August 20, 2015, the Court granted the TOs’ motion to hold the case in abeyance, subject to submission of status reports every 90 days. The most recent status report, the eighth such report filed, was filed on August 14, 2017. In that report, the parties again indicated, ultimately, that the proceedings upon which the TOs based their request for abeyance of this appeal remain ongoing. This case continues to be held in abeyance.

126 147 FERC ¶ 61,173 (May 30, 2014) (Demand Curve Order); 150 FERC ¶ 61,065 (Jan. 30, 2015) (Demand Curve Clarification Order); 155 FERC ¶ 61,023 (Apr. 8, 2016) (Demand Curve Remand Order); 158 FERC ¶ 61,138 (Feb. 3, 2017) (Demand Curve Remand Rehearing Order).

127 155 FERC ¶ 61,273 (June 16, 2016); 157 FERC ¶ 61,060 (Oct. 27, 2016).

128 153 FERC ¶ 61,378 (Dec. 30, 2015); 151 FERC ¶ 61,226 (June 18, 2015).

129 153 FERC ¶ 61,224 (Nov. 19, 2015); 153 FERC ¶ 61,223 (Nov. 19, 2015); 147 FERC ¶ 61,172 (May 30, 2014).

130 153 FERC ¶ 61,222 (Nov. 19, 2015); 150 FERC ¶ 61,053 (Jan. 30, 2015).

131 153 FERC ¶ 61,222 (Nov. 19, 2015); 150 FERC ¶ 61,053 (Jan. 30, 2015).

132 147 FERC ¶ 61,235 (June 19, 2014); 149 FERC ¶ 61,156 (Nov. 24, 2014); 151 FERC ¶ 61,125 (May 14, 2015).
• FCM Pricing Rules Complaints (15-1071**, 16-1042) (consol.)
  Underlying FERC Proceeding: EL14-7, 133 EL15-23 134
  Petitioners: NEPGA, Exelon

On March 31, 2015, NEPGA filed a petition for review of the FERC’s orders on NEPGA’s FCM Administrative Pricing Rules Complaint. On May 22, the Court granted NEPGA’s motion to hold the case in abeyance pending a decision in EL15-23 and, following the FERC’s decision in EL15-23 and Exelon’s appeal of that case (16-1042), Exelon’s motion to consolidate this proceeding with 16-1042. All briefing in the consolidated proceeding has now been completed. Oral argument has been scheduled for October 6, 2017 at 9:30 a.m. before Judges Srinivasan, Wilkins and Sentelle.

Other Federal Court Developments of Interest


In a case that will influence the FERC’s review of pipeline applications, the DC Circuit held that “the FERC must consider not only the direct effects, but also the indirect environmental effects, of [projects] under consideration.” Addressing an appeal by environmental groups and landowners challenging FERC’s approval of the construction and operation of three new interstate natural-gas pipelines in the southeastern United States, the Court found that the FERC’s environmental impact statement (“EIS”) was not adequate as it did not contain enough information on the greenhouse-gas emissions that will result from burning the gas that the pipelines will carry. On remand, the Court directed the FERC to explain in its EIS, as an aid to the relevant decision-makers, whether the FERC position’s on the Social Cost of Carbon still holds, and why. “The FERC must consider not only the direct effects, but also the indirect environmental effects, of the project under consideration. See 40 C.F.R. § 1502.16(b). “Indirect effects” are those that “are caused by the [project] and are later in time or farther removed in distance, but are still reasonably foreseeable.” Id. § 1508.8(b). The phrase “reasonably foreseeable” is the key here. Effects are reasonably foreseeable if they are ‘sufficiently likely to occur that a person of ordinary prudence would take [them] into account in reaching a decision.’”


In a decision that may ultimately impact how the FERC approaches future orders on filings that it does not find just and reasonable as filed, the DC Circuit emphasized, in response to appeals from FERC orders conditionally accepting changes to PJM’s MOPR mechanism, that Section 205 of the Federal Power Act does not allow FERC to make modifications to a proposal to make it acceptable (rather than accept those filings subject to conditions or compliance filings).

133 150 FERC ¶ 61,064 (Jan. 30, 2015); 146 FERC ¶ 61,039 (Jan. 24, 2014).
134 154 FERC ¶ 61,005 (Jan. 7, 2016); 150 FERC ¶ 61,067 (Jan. 30, 2015).
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Status Report of Current Regulatory and Legal Proceedings as of September 7, 2017

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